BP-26 Rate Case and TC-26 Tariff Proceeding Workshop

August 27-28, 2024

Agenda August 27 (Day 1)

BP/TC-26 Pre-Proceeding Workshop		
Time*	Topic	Presenter
9:00 – 9:05 a.m.	Introduction, Meeting Protocols, Comments and Agenda	Brian McConnell
9:10 – 9:25 a.m.	Power Rates – Natural Gas Price Forecast	Aimee Robinson
9:30 – 10:15 a.m.	Generation Inputs Capacity Costs	Jonathan Ramse, Matthew Pham, Garth Beavon
10:15 – 10:30 a.m.	**Break**	
10:30 – 12 p.m.	Power and Transmission Risk	Zach Mandell
12 – 1 p.m.	**Lunch**	
1 – 2:15 p.m.	Revenue Financing	Ethan Postrel
2:15 – 3 p.m.	Power and Transmission Revenue Requirement	Alex Lennox, Tracy Carlson, Quay Rubin
3:05 – 3:30 p.m.	Interconnection Credits (GI and Non-GI)	Paul Hermanson
	Closing Remarks	

**** Times are approximate***

Agenda August 28 (Day 2)

BP/TC-26 Pre-Proceeding Workshop		
Time*	Topic	Presenter
9:00 – 9:05 a.m.	Introduction, Meeting Protocols, Comments and Agenda	Brian McConnell
9:10 – 9:30 a.m.	Power Rates – Transfer Service Delivery Charge	Jason Boen
9:35 – 9:45 a.m.	Energy Storage Devices	Eric King, Frank Puyleart
9:50 – 10:50 a.m.	Generation Inputs Rates	Bill Hendricks, Nancy Morales, Frank Puyleart
10:55 – 11 a.m.	**Break**	
11 a.m. – 12 p.m.	GI Withdrawal Penalties	Rebecca Fredrickson, Bill Hendricks, Rahul Kukreti
12:00 – 1 p.m.	**Lunch**	
1:00 – 1:30 p.m.	GI Reforms – LGIA Update and Status of BPA Option to Build	Kim Gilliland, Katie Sheckells
1:35 – 1:55 p.m.	Draft Proposed Tariff (redline), including Tariff Clean up (ministerial edits to Attachments L and R)	Melanie Bersaas, Colleen McDonnell
2 – 2:15 p.m.	TC-26 Settlement – Proposed Initiation and Next Steps	Brian McConnell, Melanie Bersaas
	Closing Remarks	

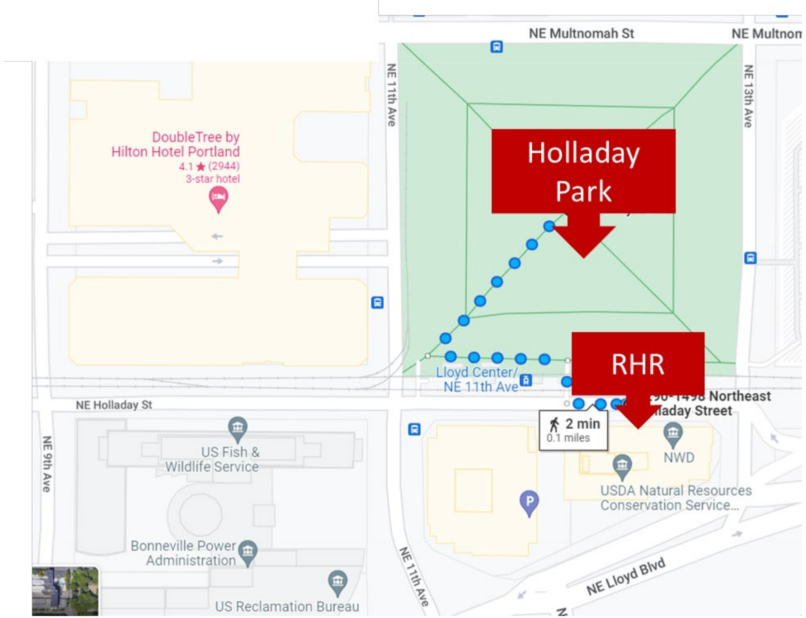
**** Times are approximate***

Webex Format Update

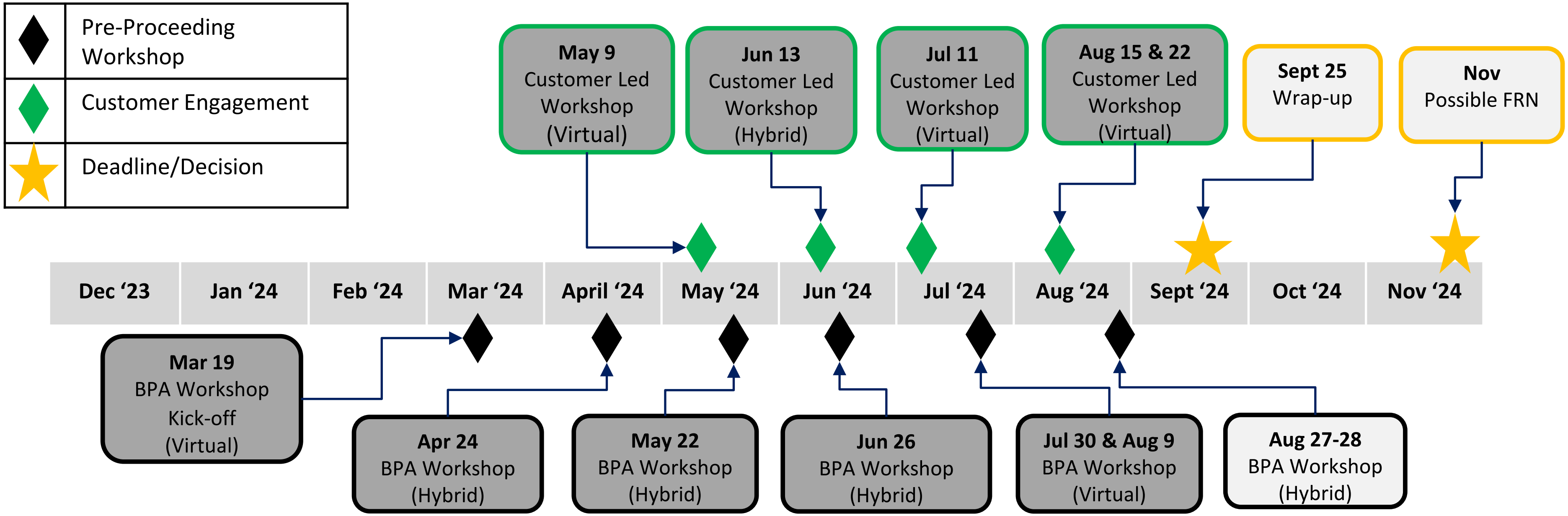
- BPA has adjusted its public stakeholder virtual engagement approach.
- The Webex format is moving to a “webinar” style.
  - Webex attendees can no longer mute/unmute themselves or enable their webcam.
- The all-chat feature is disabled. Attendees can only message panelists.
  - To participate, attendees must raise their hand (BPA will unmute you to enable your participation), or send a question to panelists in the chat.
- If you are Webex by phone only: press *3 to request to be unmuted.
- Moderators will continue to address raised hands in the order received.
  - Please continue to state your name and affiliation.
- As necessary, BPA may evolve these procedures and take other measures at its discretion to prevent future disruptions.

Safety Moment

- The Rates Hearing Room has two exits.
- In the event an alarm sounds, please meet at Holladay Park across the street.



Proposed BP/TC-26 Pre-Proceeding Workshop Schedule



Procedural schedule dates are draft only

Approach to Customer Engagement

- Most identified issues will be presented according to the following process at workshops (multiple steps might be addressed in a single workshop):

Phase One: Approach Development	Phase Two: Evaluation	Phase Three: Proposal Development
Step 1: Introduction & Education	**Step 3: Analyze the Issue**	**Step 5: Discuss Customer Feedback**
Step 2: Description of the Issue	**Step 4: Discuss Alternatives**	**Step 6: Staff Proposal**

Teams will follow the steps that may be covered in one workshop or more based on the complexity of the issue.

Customer Comment Process

- Thank you to everyone who submitted comments on the July 30 and Aug. 9 workshop topics.
- BPA is using the same comment tracking and response process that was developed in BP/TC-24, which includes the following:
  - All customer comments will be posted to the BP-26 Rate Case website.
  - BPA will create a consolidated customer response (CCR) document for each workshop that will be posted/updated at the same time as other workshop materials.
  - The CCR is organized to address comments listed by the workshop date where the comments were received.
  - The CCR will provide direct responses or identify other forums or future BP/TC-26 workshops where BPA expects to provide a response.
    - To the extent possible, BPA will endeavor to provide responses prior to the next workshop in the Customer Comments section on the BP-26 website (updated CCR will be posted with workshop materials)
    - All comments will have a response

July 11 Customer Led Workshop

- During the July 11 BP-26 Customer-Led Workshop, two topics were discussed
  - Short Distance Discount
    - An examination of the Short-Distance Discount for NT service and PTP customers is something that we are not able to accommodate within the scope of BP-26. BPA does see value in the discussion and would be amenable to opening the subject in future rates cases.
  - Utility Delivery Roll In
    - BPA intends to bring a proposal during the September workshop.

BP-26 and TC-26 Workshop

August 27, 2024
(Day 1)

Natural Gas Price Forecast

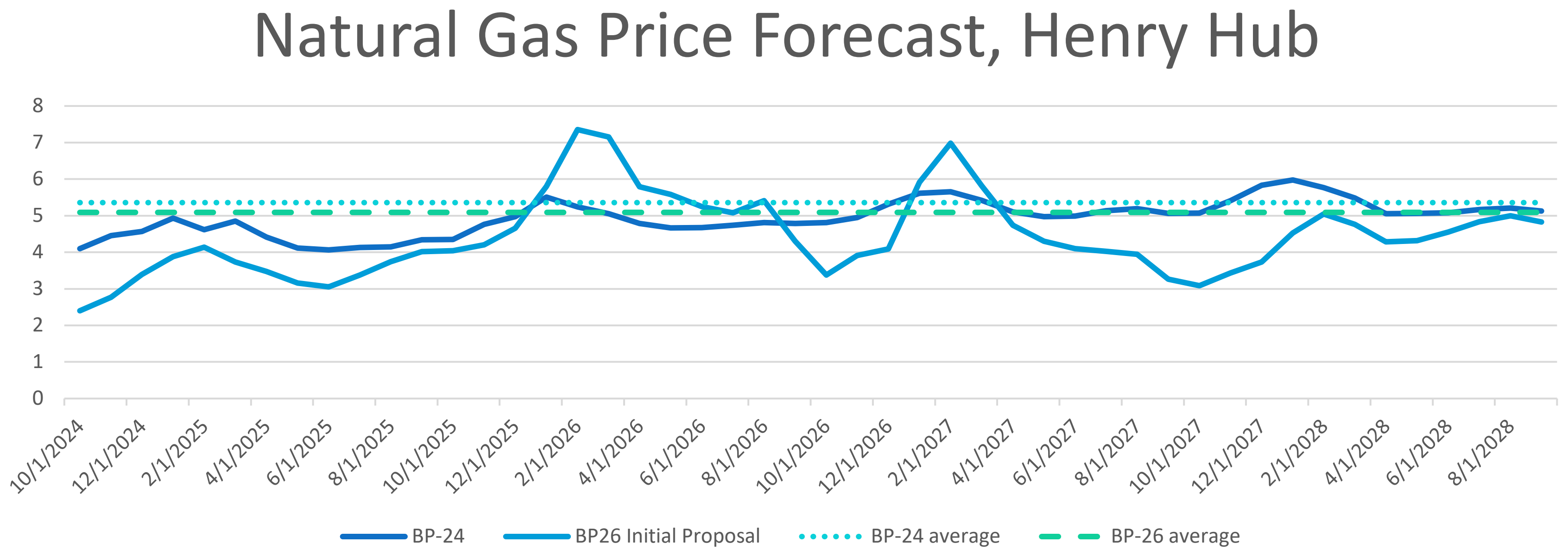
Market Fundamentals

- Demand
  - LNG export facilities
  - Power burn
- Supply
  - Less production being cut than might be expected
- Storage
  - Healthy storage levels across the country

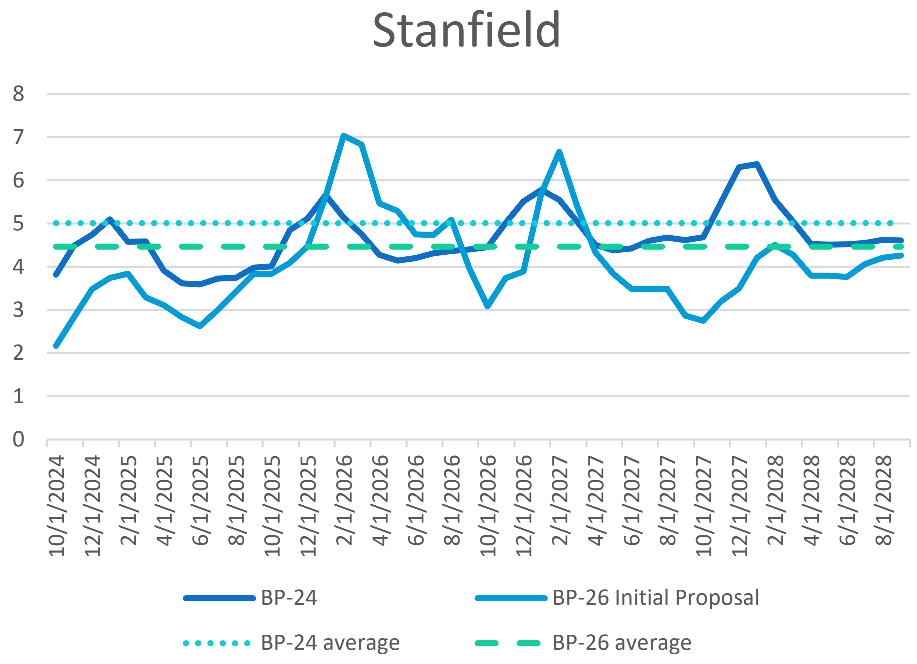
Forecasting Gas Prices

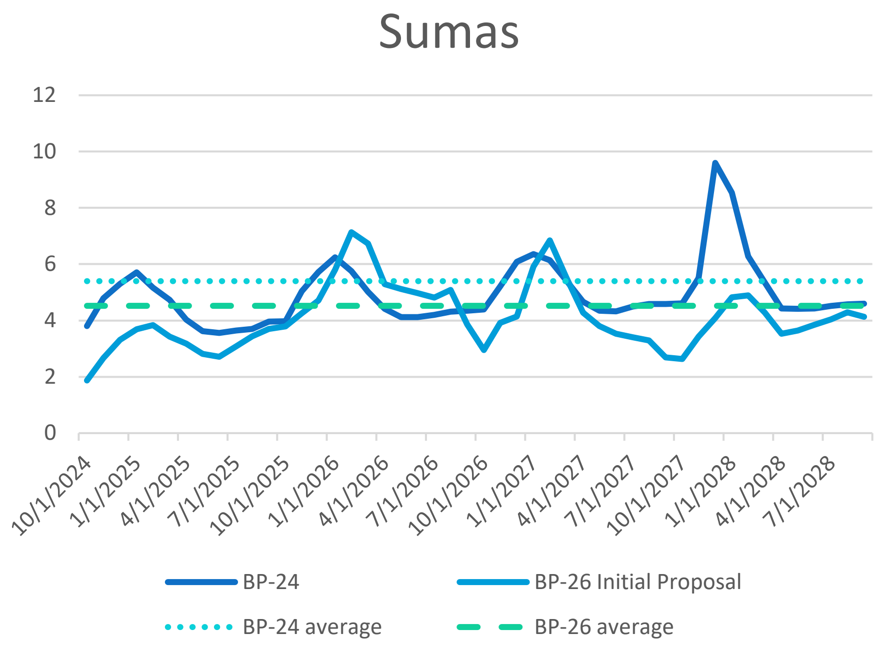
- Aurora takes natural gas price forecasts as an input for electricity price forecasts
- BPA’s gas forecast is prepared using information from:
  - Consultants
  - Henry Hub futures contract pricing
  - EIA energy outlook data
- The gas forecast provides monthly prices for Henry Hub and basis values for 11 other hubs in the Pacific Northwest, Southwestern U.S., and Western Canada.

Gas Prices Lower Over BP-26



Gas Prices Lower Over BP-26





Generation Inputs: Capacity Costs

Objectives

- Background education on Generation Inputs and capacity costs.
- Understand embedded and variable costs.
- Provide overview of anticipated drivers of embedded costs for BP-26.
- Share proposed changes to variable cost modeling.

Background on Generation Inputs

- Generation Inputs are the reserve generation capacity and other services needed for Ancillary and Control Area Services (ACS) and Transmission.
- Bonneville holds two types of reserve capacity:
  - Balancing (INC and DEC): Regulation and Non-Regulation
  - Operating Reserves (INC): Spinning and Supplemental

Background on Generation Inputs Costs

- Bonneville Power allocates the total power Revenue Requirement (excluding conservation costs) as either:
  - Energy (approx. $2 Billion) or,
  - Capacity (approx. $1 Billion)
- Generation Inputs costs are composed of two parts:
  - **Embedded Unit Costs** are calculated by dividing the revenue requirement allocated to capacity divided by the 1-hour peaking capacity of the federal system. For BP-24 this was:

$$\frac{\$1.06\ Billion}{14{,}212\ MW} = \$6.24\ kW/month$$

  - **Variable Unit Costs** are calculated for each reserve type in the Generation and Reserve Dispatch (GARD) Model. For BP-24, total variable costs were $17.4 Million.
- Incremental Capacity Unit Costs = Embedded Unit Cost + Variable Unit Cost
- Decremental Capacity Unit Costs = Variable Unit Cost

Preliminary BP-26 Capacity Costs

Component:	BP-24 ($/kW/mo)	BP-26 ($/kW/mo)	Change
Value Delta:	$ 3.72	$ 4.71	$0.99 (27%)
Unit Costs:			
Reg. BAL INC	$ 8.82	$ 10.11	$1.29 (15%)
Reg. BAL DEC	$ 0.99	$ 0.00	-$0.99 (-100%)
Non-reg. BAL INC	$ 5.10	$ 5.40	$0.30 (6%)
Non-reg. BAL DEC	$ 0.05	$ 0.00	-$0.05 (-100%)

- A market-based value delta is applied to the incremental regulation and non-regulation balancing reserve costs. This delta does not change the total revenue forecast, but rather fixes the total revenue and delta between the reg. and non-reg. unit costs and solves for the unit costs themselves.
- INC unit costs include both embedded and variable costs while DEC unit costs only include variable costs.

Preliminary BP-26 Capacity Costs

Two Cost Component:	BP-24 Unit Cost ($/kW/mo)	BP-26 Unit Cost ($/kW/mo)	Change
Embedded Cost:	$6.24	$8.06	$1.82 (29%)
Variable Costs:	*	*	*

** BPA is proposing to change the variable cost methodology for the BP-26 rate period. An explanation of this new method is covered in later slides.*

- Preliminary modeling of the Embedded Costs should not be considered final:
  - The input forecasts that go into the Capacity Cost study will change for the Initial Proposal. Overall, Bonneville staff expects that the unit cost increase will not be as large as what is shown above.
  - With that caveat in mind, several key drivers can be described to explain the 29% increase above: (a) increase in financing costs, (b) increase in fish and wildlife costs, and (c) increase in forecast power purchases.

Background on Variable Reserve Costs

- Variable reserve costs represent the energy costs incurred by holding reserves on the FCRPS.
- Bonneville has used the Generation and Reserves Dispatch (GARD) Model to measure these costs since BP-12.
- Stand-ready energy costs are incurred due to changes in operational efficiency. These general costs are categorized into three buckets:
  - Energy Shift: measures the shift in generation from HLH to LLH periods.
  - Spill: measures the spill required to maintain INC reserve requirement and specific project flow requirements.
  - Efficiency: measures the change in turbine efficiency due to holding reserves.

Previous GARD Costs

- Average annual GARD Cost ($ millions):

BP-12	BP-14	BP-16	BP-18	BP-20	BP-22	BP-24
$25.9	* $14.2	* --	* --	* --	$11.8	$17.4

*Settled Generations Inputs rates

- Variable costs are added to embedded costs and included in Ancillary and Control Area Service (ACS) rates.
- Revenue stream serves as credit in Power rates model.
- BP-22 and BP-24 include cost offsets due to Bonneville's participation in the Western EIM.
  - BP-22: 50% cost offset for non-regulation balancing reserves.
  - BP-24: 95% cost offset for non-regulation balancing reserves.

Potential Limitations to Using GARD

- Turbine specification updates are cumbersome and difficult to administer by rates staff.
- High level of cost volatility given overall minimal cost contribution to generation inputs.
- Calculating costs of four projects (GCL, CHJ, JDA, TDA) does not reflect a “system approach” like the embedded costs methodology. Although, the big four projects do account for the majority of AGC reserve deployments.
- Current energy market trends, including the increased likelihood of HLH/LLH price inversions, implies BPA may not want to load factor by shaping energy from LLH periods to HLH periods (or from GvYd to SpPk). This is an underlying assumption of the GARD Model.

BP-26 GARD Test Scenario

- Reserve Requirement for BP-26 preliminary testing:
  - Balancing Reserves: 873 MW INC & - 969 MW DEC
  - Operating Reserves: 556 MW INC
- GARD Test Results:

	Reg INC	Reg DEC	Nonreg INC	Nonreg DEC	OR INC	Total:
Energy Shift	2,380,910	732,724	-	-	4,560,898	**7,674,532**
Efficiency	5,450	(881,352)	-	-	(1,945,910)	**(2,821,813)**
Spill	1,263,962	-	-	-	5,512,585	**6,776,548**
Total:	**3,650,322**	**(148,628)**	**-**	**-**	**8,127,573**	**11,629,267**

Proposed Method

- Staff propose to use generation data from RiverWare and price the expected impact of holding reserves using the Mid-C Aurora price forecast to calculate the variable costs of reserves.
- The RiverWare model produces an hourly simulation of the regulated hydro projects' operations using HYDSIM data as inputs.
- The proposed method will only cost Regulation Balancing Reserves (INC and DEC) and Operating Reserves (INC). Non-regulation reserves will not be included because it is largely bid into the western EIM and therefore Power has an opportunity to recoup the energy costs of holding reserves.
- Reserve costs would be calculated for incremental and decremental reserves separately to measure their isolated impacts on the system.

Proposed Method

Updated methodology:

$$Unconstrained\ Gen_H - Base\ Case\ Gen_H = Generation\ Delta_H\ (MWs)$$

$$\left|\min\left(\sum_{H=1hr}^{24} Negative\ Deltas, \sum_{H=1hr}^{24} Positive\ Deltas\right)\right| = Energy\ Shift\ Delta\ (MWs)$$

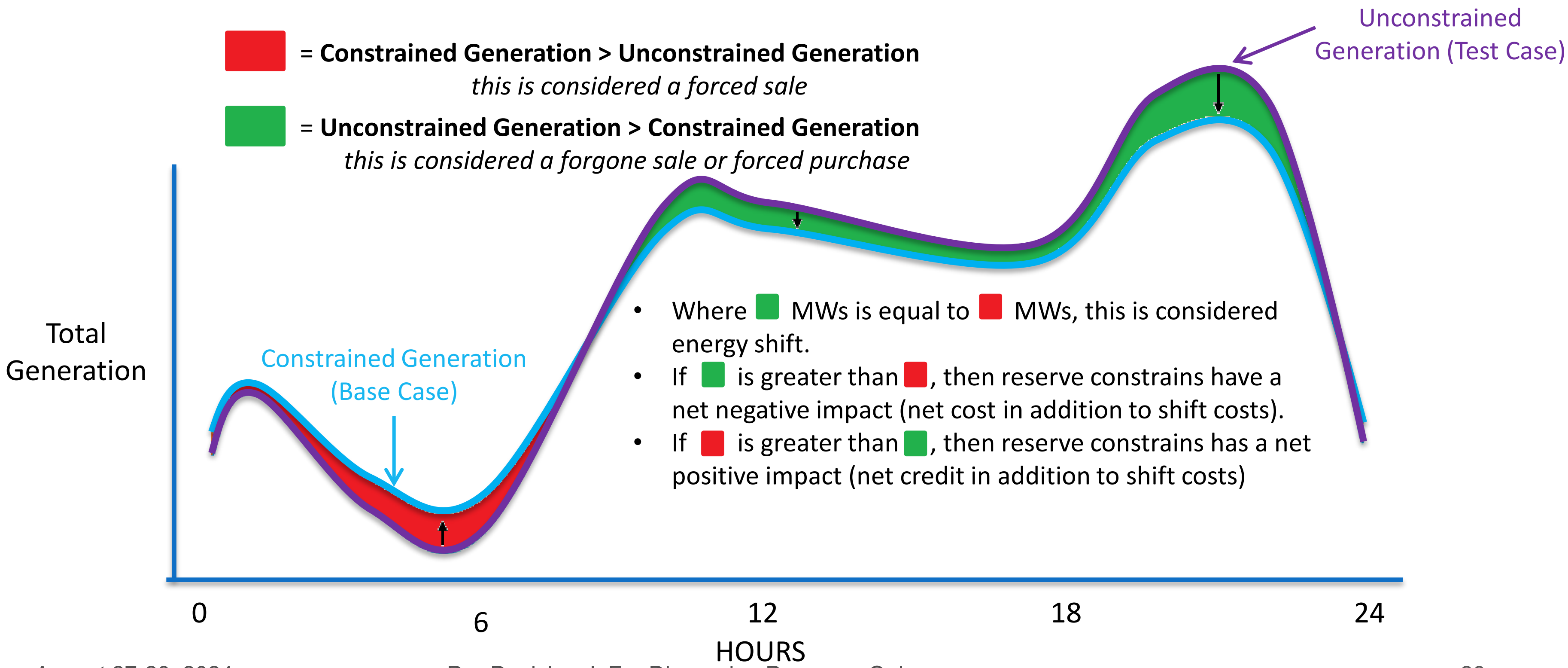
$$\sum_{H=1hr}^{24} Negative\ Deltas + \sum_{H=1hr}^{24} Positive\ Deltas = Net\ Gen\ Delta\ (MWs)$$

$$(Energy\ Shift\ Delta \times Price\ Spread) + (Net\ Gen\ Delta \times Avg.\ Price) = Total\ Daily\ Reserve\ Variable\ Cost$$

- **Unconstrained Gen**: RiverWare model assumes total hourly generation when the isolated reserve constraint is removed.
- **Base Case Gen:** RiverWare model assumes total hourly generation when all reserve constraints are held.
- **Generation Delta:** represents the change in hourly generation due to holding reserves. The total generation delta is adjusted to exclude outliers.
- **Energy Shift Delta:** represents the impact that reserves have on operators' ability to load factor the hydro system.
- **Net Generation Delta:** represents the net impact on generation. Includes, among others, impacts due to spill and turbine efficiency.
- **Price Spread:** the absolute value of the delta between monthly HLH and LLH prices.
- **Avg. Price:** the weighted average of the monthly HLH and LLH prices.

$$\sum_{D=1day}^{365} Variable\ Reserve\ Cost_D = Total\ Annual\ Variable\ Reserve\ Cost$$

Valuing Energy Shift



Comparing GARD and the RiverWare Approach

- Similarities:
  - Both models simulate hydro operations with and without holding reserves and price that delta to get a total variable cost.
  - Both models use the Aurora Mid-C price forecast.
  - Both models use the same reserve data inputs (Balancing and Operating Reserves).
- Differences:
  - The GARD model calculates costs associated with four hydro projects while the RiverWare model assumes a whole system approach.
  - The GARD model specifies three distinct impacts of holding reserves while the RiverWare model specifies two.
  - The GARD model uses monthly four-period pricing while the RiverWare model uses monthly high/low spread and average prices.
  - The GARD model requires rates staff to update specifications on project turbines while all hydro assumptions are managed by PG staff for the RiverWare model.

Comparing GARD and the RiverWare Approach

GARD	Reg INC	Reg DEC	OR INC	Total:
Energy Shift	2,380,910	732,724	4,560,898	**7,674,532**
Efficiency	5,450	(881,352)	(1,945,910)	**(2,821,813)**
Spill	1,263,962	-	5,512,585	**6,776,548**
Total:	**3,650,322**	**(148,628)**	**8,127,573**	**11,629,267**

RW + Pricing	INC	DEC	Total:
Energy Shift	443,789	313,348	**757,137**
Net Gen Delta	9,408,637	483,084	**9,891,721**
Total:	**9,852,426**	**796,432**	**10,648,858**

- When we assume non-regulation variable costs are excluded from the GARD model, the two approaches have similar results. The RW approach is 8.4% lower than costs calculated by GARD.
- Staff believe using the RiverWare model is the preferred approach for BP-26 and into the future.
- When, and if, Bonneville joins a day-ahead market, further refinements may be required to model the variable costs of holding reserves.

Power and Transmission Risk

Risk Study Overview

The Power and Transmission Risk Study serves to ensure that BPA meets the Treasury Payment Probability (TPP) Standard and implements BPA's Financial Reserves Policy (FRP)

TPP Standard: BPA must set rates high enough to have at least a 95% probability of making all payments to the Treasury over a two-year rate period.

FRP Implementation: BPA must establish tools to meet FRP objectives for managing business line and agency financial reserves.

Risk Study Overview (TPP Standard)

- The 95% TPP Standard is based on a two-year rate period.
- The TPP target must be adjusted for this three-year rate period. This is done by calculating the single-year equivalent of the two-year standard (97.5%) and then scaling up to a three-year equivalent.
- The three-year equivalent TPP Standard is 92.59%.

Risk Study Overview (continued)

- The Risk Study defines and evaluates the tools used to implement the FRP and ensures BPA meets the TPP standard. The Study uses probabilistic modeling of revenues, expenses, and Reserves for Risk (RFR) to measure TPP and the effectiveness of the risk mitigation tools.
- For BP-24, BPA included three risk mechanisms for each business line. These were the Cost Recovery Adjustment Clause (CRAC), the FRP Surcharge, and the Reserves Distribution Clause (RDC). The trigger metric for each of these mechanisms was set based on end-of-year actuals. If a risk mechanism triggered it would adjust rates for December-September of the following fiscal year.
- Staff plan to propose these same tools for the BP-26 Initial Proposal. An additional tool, Planned Net Revenue for Risk (PNRR), is available to meet the TPP standard.

Risk Study Overview, Risk Mechanisms

- Cost Recovery Adjustment Clause (CRAC): increases rates for the following fiscal year when below a threshold ($0 in RFR) at the end of a fiscal year.
  - For Transmission, the CRAC triggers “dollar for dollar” up to maximum of $100 million. For Power, it triggers dollar for dollar up to $100 million, then “50¢ on the dollar” up to $300 million.
- FRP Surcharge: increases rates for the following fiscal year when below 60 days cash on hand at the end of a fiscal year.
  - The maximum annual surcharge is proposed to be $40 million for Power and $15 million for Transmission.
- Reserves Distribution Clause (RDC): A mechanism for identifying reserves the Administrator shall consider for rate reduction, debt repayment, incremental capital investment, or any other high-value purpose when a business line is above 120 days cash *and* the agency is above 90 days cash at the end of a fiscal year.
- Planned Net Revenue for Risk (PNRR): A fixed amount of additional revenue added to the Revenue Requirement which increases reserves over the rate period.

Expected Changes

There are two notable changes to risk modeling anticipated for BP-26:

1. Accrual to Cash risk model removal (NORM)
2. Modeling tool conversion (NORM)

Additionally, changes to modeled Treasury Note utilization (Toolkit) are being considered for BP-26.

Accrual to Cash Risk Model Removal

Currently the accrual to cash risk is modeled solely upon the effect of the Slice True-Up for Power.

Proposal: simplify risk study by sunsetting accrual to cash risk model.

Justification: Cash timing risk is mitigated through within-year liquidity tools. Magnitude of impact on reserves risk is proportional to slice share.

Modeling Tool Conversion

- Staff is exploring replacing a vendor tool for the NORM risk models for cost savings, continuity, and reliability.
- BP-24 NORM models use Palisades @Risk, an Excel plug-in.
- BP-26 will develop in parallel @Risk and R code for benchmarking and validation.
  - Benefits: avoided license fees, vendor risk, uses open source that supports replicability and transparency.
- Intend to publish initial proposal with new version if we can validate with confidence.

Changes to Treasury Note

- Currently Toolkit relies upon $430M of the Treasury Note facility to support the TPP calculation.
- Given the changing risk landscape, Staff are evaluating setting aside more of the facility for within-year liquidity for BP-26.
- Impacts to PNRR or other risk mitigation measures will be evaluated by BP-26 IP.

BPA Response to 8/15/2024 Customer Presentation on MRNR and Revenue Financing

Recap of Customer Perspective

Two parts

1. There is a problem.
   - MRNR due to Revenue Financing leads to double-/over-recovery because Revenue Financing is an acceleration ("prepayment") of depreciation expense.
2. Here is a solution.
   - BPA should record a regulatory or deferred liability.

BPA Staff Response: BLUF

Two parts

Revenue Financing does not result in over-recovery.
We'll go into greater detail on this…

1. There is a problem.
   – MRNR due to Revenue Financing leads to double-/over-recovery because Revenue Financing is an acceleration ("prepayment") of depreciation expense.

2. Here is a solution.
   – BPA should record a regulatory or deferred liability.

Since there's no problem, there's no need for a remedy, and discussion of a solution is moot. We'll forego greater detail on this.

BPA Staff Response

- Revenue Financing ≠ over-recovery
  - BPA does not tie the source of financing to specific assets (other than lease financing).
  - Depreciation takes into account more than the original financing cost, e.g. removal and salvage, to recognize the loss of value over an asset’s expected useful life.

BPA Staff Response: Revenue Requirement

Two-tiered Revenue Requirement Test:
Do not intentionally set rates to operate at a loss from accrual- or cash-based perspective.

Accrual based

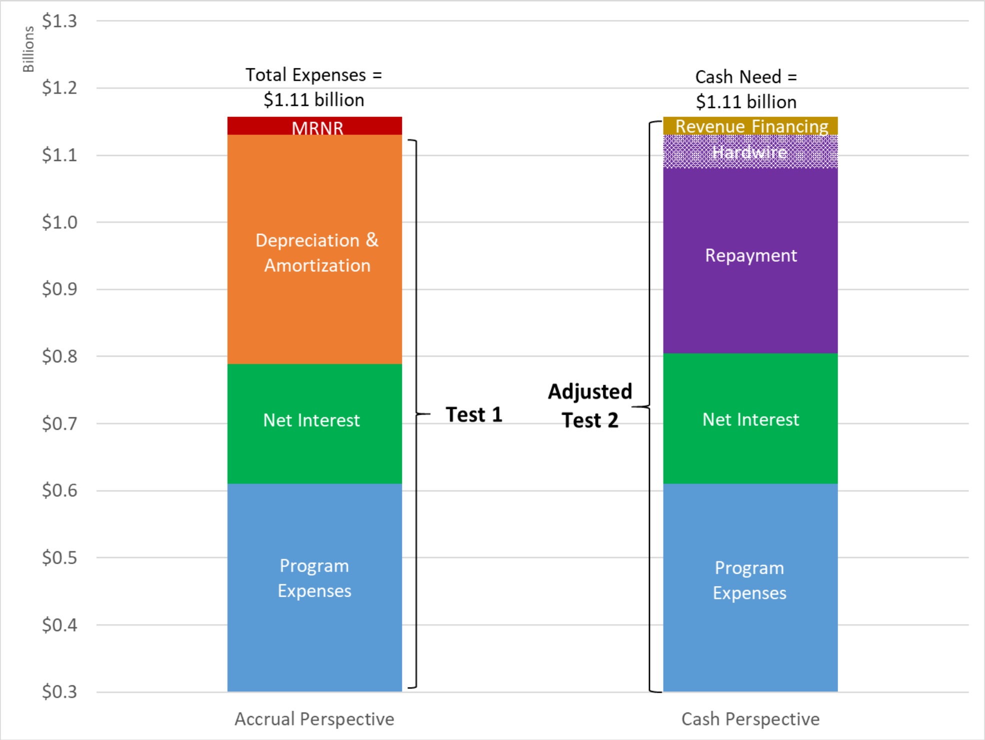
Set rates to recover expenses within each rate period.

Cash based

Set rates to recover cash needs within each rate period.

These are "higher-of"; not additive.

BPA Staff Response: Revenue Requirement



BPA Staff Response: RF Benefits

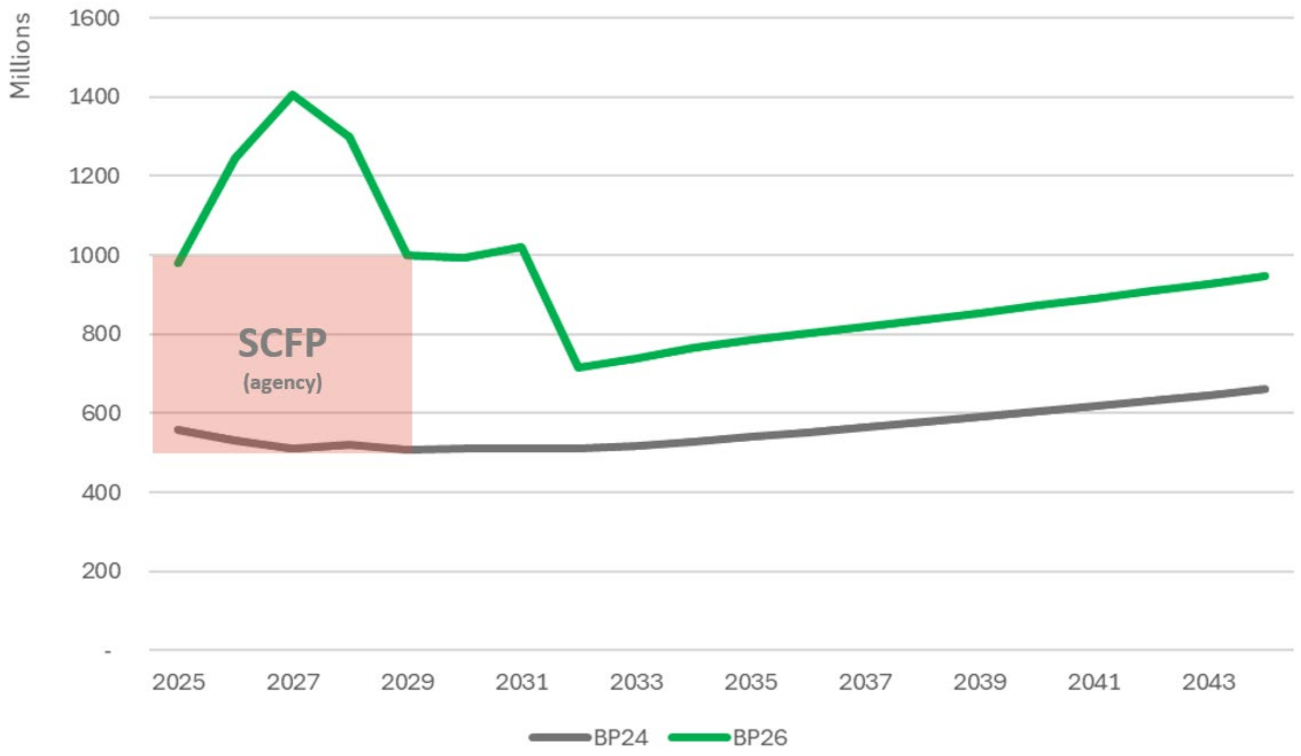
- Benefits of Revenue Financing
  - Under the Sustainable Capital Financing Policy, Revenue Financing may also be used within the operating year to repay existing debt (e.g. with higher interest rates) and support business-line liquidity needs.
  - Revenue Financing provides long-term benefits of reduced interest expense, financial flexibility, and a more consistent cost of service over time.

Increased Transmission Revenue Financing Due to Increased Transmission Capital Investment Program

Background

- Transmission’s 2024 IPR capital forecast is approximately $7 billion higher than the 2022 IPR capital forecast used in BP24, driven by the demand for Transmission system expansion, including Evolving Grid projects.

Background (cont.)



Forecasted capital spend significantly exceeds prior plans, especially in early years.

Strain on Financial Objectives

BP-24 → **2040 T Leverage: 60%**

BP-26 → **2040 T Leverage: 74%**

KPI: 2040 Leverage ≤60%

Recap: Sustainable Capital Financing Policy

- Based on agency capex of $.5b - $1b per year
- Default 10% Revenue Financing (RF)
- Phase-in approach of 1% rate impact, $15m RF per year
- Provides for modifications in response to circumstances
  - "BPA may propose or adopt an amount of revenue financing for a given rate period that is greater than or less than the default amount, in response to circumstances including, but not limited to: changes in BPA's capital program, prior or forecast triggering of risk adjustment mechanisms, rate pressure, settlement, likelihood of achieving the debt-to-asset ratio policy goal, or whether an amount of revenue financing greater or less than the default amount occurred in a prior rate period."

Alternatives: Transmission & Agency Impacts

Alternatives Considered	2040 Leverage: T / Agency	Incremental Rate Pressure From New RF
BP-24	60% / 56%	N/A
BP-26 w/ 1% limiter	74% / 65%	0%
BP-26 w/ new $55m RF	72% / 64%	3.4%
BP-26 w/ new $148m RF	65% / 60%	9.2%
BP-26 w/ new $195m RF	60% / <60%	12.2%

Alternative Selected

Returns to Base ~10% Revenue Financing	2040 Leverage: T / Agency	Incremental Rate Pressure From New RF
BP-24	60% / 56%	N/A
BP-26 w/ 1% limiter	74% / 65%	0%
BP-26 w/ new $55m RF	72% / 64%	3.4%
BP-26 w/ new $148m RF	65% / 60%	9.2%
BP-26 w/ new $195m RF	60% / <60%	12.2%

BP-26 Revenue Requirements

Overview

- Changes & Updates to Methodologies & Assumptions
  - Forecasting amortization of non-federal premiums & cost of issuance
  - Gains/Losses on CGS decommissioning trust fund
  - Amortization period of Cowlitz Falls
  - Litigation settlements
  - Grand Coulee switchyard ownership transfer
- Income Statement & Cash Flow Tables

CAVEAT: ALL NUMBERS ARE PRELIMINARY.

THE INITIAL PROPOSAL MAY VARY.

Changes and Updates

Non-Federal Premiums (Power Only)

- In FY2020, BPA changed the accounting treatment of non-federal debt, displaying it more like federal debt.
- New bonds issued to refinance old bonds are usually issued at a premium, i.e. higher interest rate but lower principal.
- The amortization of non-federal premiums is a reduction to interest expense, comparable to the Capitalization Adjustment. It is a non-cash expense
- In BP-22, the revenue requirements began showing the amortization of non-federal premiums (premiums). Forecasts were not included.
- BP-24 included forecasts of the amortization of premiums associated with projected RCD transactions.
- Amortization of the premiums has a net zero impact because it is offset by an equal, opposite change in MRNR, i.e. MRNR goes up to offset the reduction to interest.

Forecasting the Amortization of Premiums

- Premiums vary with each RCD transaction.
  - Range from 12% to 22% of the total amount of bonds to be refinanced
  - Amortized over the life of the new bonds
  - Propose to use 12% to calculate the total premium that is amortized over 10 years
- Actuals will vary because multiple bonds are issued with differing maturities
- There is no rate impact. The increase in amortization is offset by matching reduction to Minimum Required Net Revenues (MRNR).

($000s)	Bonds	Premium	Years to Amortize	Annual Premium	2026	2027	2028
		Premiums through 2024			36,603	34,139	31,131
2025	357,155	35,716	10	3,572	3,572	3,572	3,572
2026	388,065	38,807	10	3,881	970	3,881	3,881
2027	342,640	34,264	10	3,426	-	857	3,426
2028	523,750	52,375	10	5,238	-	-	1,309
Total					41,145	42,448	43,319

Note: "Premiums through 2024" also includes the amortization of the cost of issuance.

Non-Federal Cost of Issuance (Power Only)

- Forecasting amortization of the Cost of Issuance (COI) of non-federal debt is new for BP-26. The treatment of the Cost of Issuance also changed in FY 2020.
- The cost to issue debt is amortized over the life of the associated bonds. Each transaction is different with a different mix of maturities decided as the bond deal is being developed.
- We assume the COI for each transaction is $1 million.
- The COI is amortized over the life of the bonds. We propose 10 years.
- Amortization of COI increases interest expense, but it is a non-cash expense.
- Amortization of COI has a net zero impact because it is offset by an equal, opposite change in MRNR.

($000s)	COI	Years to Amortize	Annual Amount	2026	2027	2028
2024	825	10	83	83	83	83
2025	1,000	10	100	100	100	100
2026	1,000	10	100	100	100	100
2027	1,000	10	100	25	100	100
2028	1,000	10	100	-	25	100
				308	408	483

Gains/Losses on CGS Trust Fund (Power Only)

- As the actual value of investments (i.e. increase or decrease in stock price) in the CGS Decommissioning Trust Fund change, the gains or losses of that value are recognized on the income statement.
- BPA proposes to not forecast gains or losses.
  - They are entirely dependent on swings in market value which are not predictable.
  - It has no impact on the total revenue requirement. The Gains/Losses are a non-cash reduction to interest expense. They are fully offset to changes to MRNR. The total revenue requirement stays the same.

Amortization of Cowlitz Falls (Power Only)

- As part of the 2020 non-federal debt accounting change, Bonneville began amortizing (comparable to depreciating) non-federal assets.
- Cowlitz Falls was being amortized through 2036 when the license expires, consistent with how CGS was treated.
- However, Bonneville's agreement with Lewis County PUD ends in 2032, four years before the license expires.
- In BP-24, the amortization period was shorted to match the remaining life of the agreement.
- This increases Cowlitz Falls amortization expense by $1.2 million/year (to $5.4 million from $4.2 million) but is offset by a matching reduction to MRNR.

Litigation Settlements (Power Only)

- The federal government, including Bonneville, entered into two agreements to achieve a long term stay in litigation.
- The spending associated with these agreements include:
  - Phase 2 Implementation Plan (P2IP): $200 million (plus inflation) paid over 20 years, 2024-2043 to test the feasibility of the reintroduction of anadromous salmonids in blocked habitats above Chief Joseph and Grand Coulee dams.
  - Six Sovereigns (6S): $100 million (plus inflation) paid over 10 years for projects that contribute to the restoration of salmon and other native fish populations
  - Lower Snake River Compensation Plan hatchery facilities: $200 million over 10 years for modernization, upgrades, and non-recurring maintenance
  - Bonneville proposes to treat these commitments as regulatory assets.
- Bonneville also entered into two new long term budget agreements (Accords) with the Coeur d'Alene Tribe and the Spokane Tribe of Indians.
  - This spending embedded in BPA's direct Fish & Wildlife program, which is an expense that appears on the income statement.

Litigation Settlements – P2IP

- $200 million (plus inflation, $256 million total) to be paid over 20 years, 2024-2043
- We are proposing to treat the $256 million as a regulatory asset to be amortized over 18 years (2026-2043). Annual amortization would be $14.2 million (being treated as non-IPR O&M), which is offset by a matching reduction to MRNR. No rate impact.
- The annual payments to the P2IP parties will be treated as a balance sheet-only cash payment. They will appear on the revenue requirement statement of cash flows, increasing MRNR. There is no offset.

($000s)	2026	2027	2028
Inflation Rate	2.29%	2.18%	2.23%
P2IP Payment	10,600	10,843	11,079
P2IP Amortization	14,222	14,222	14,222

Litigation Settlements – Six Sovereigns

- $100 million (plus inflation, $111.2 million total) to be paid over 10 years, 2024-2033
- We are proposing to treat the $111.2 million as a regulatory asset to be amortized over eight years (2026-2043). Annual amortization would be $13.9 million (being recorded as non-IPR O&M), which is offset by a matching reduction to MRNR. No rate impact
- The annual payments to the six Sovereigns will be treated as a balance sheet-only cash payment. They will appear on the revenue requirement statement of cash flows, increasing MRNR. There is no offset.

($000s)	2026	2027	2028
Inflation Rate	2.29%	2.18%	2.23%
6S Payment	10,600	10,843	11,079
6S Amortization	13,900	13,900	13,900

Summarizing P2IP & 6S Impact

	($000s)	No Settlements	Add Settlement Payments	Add Amortization	Change from No Settlements
	Income Statement				
1	Amortization of Settlements	-	-	28,122	28,122
2	MRNR	158,557	179,757	151,635	(6,922)
3	Total	158,557	179,757	179,757	21,200
	Statement of Cash Flows				
4	Cash from Operating Activities				
5	MRNR	158,557	179,757	151,635	(6,922)
6	Non-Cash Items				
7	Amortization of Settlements	-	-	28,122	28,122
8	Settlement Payments	-	(21,200)	(21,200)	(21,200)
9	Other Items	376,267	376,267	376,267	-
10	Total Cash from Operating Activities	376,267	355,066	383,188	6,922
11					
12	Cash for Investment Activities	(421,916)	(421,916)	(421,916)	-
13					
14	Cash from Borrowing & Appropriations				
15	Bebt Issued	384,916	384,916	384,916	-
16	Repayment of Debt	(477,161)	(477,161)	(477,161)	-
17	Irrigation Assistance	(20,662)	(20,662)	(20,662)	-
18	Total Cash from Borrowing & Appropriations	(112,908)	(112,908)	(112,908)	-
19					
20	Change in Cash Flow	-	-	-	-

- The amortization of the settlements nets out with the change in MRNR.
- The net change to the revenue is driven by the cash payments, $21.2 million, which affect the calculation of MRNR.

Litigation Settlements – Lower Snake

- $200 million to be paid over 10 years
- We are proposing to treat the spending as a regulatory asset. Regulatory asset treatment would allow the spending to be capitalized and to be funded with Treasury bonds.
- Each increment of spending will be amortized over 10 years, which is also the maximum life of the bonds.
- Estimation of amortization expense is shown below.

($000s)	Investment	Cummulative Investment	Monthly Amortization	2026	2027	2028
2025	1,700	1,700	14	170	170	170
2026	11,780	13,480	98	589	1,178	1,178
2027	19,400	32,880	162	-	970	1,940
2028	28,255	61,135	235	-	-	1,413
Total				759	2,318	4,701

Grand Coulee Switchyard Transfer (Power & Transmission)

- Bonneville and the Bureau of Reclamation negotiated the transfer of ownership of three Grand Coulee switchyards from Reclamation to Bonneville-Transmission. Net book value = $119 million
- BP-24 assumed that the transfer would occur in FY 2022, which did not occur.
- Current expectation:
  - Agreement signing, September 2024
  - Ownership transfer, October 1, 2024
- O&M will gradually transfer to Bonneville.

Grand Coulee: Impact on Costs

- The switchyards perform network and utility deliver functions.
- The O&M and capital costs were estimated and assigned to transmission through a between business line (BBL) charge.
- The BBL charge was about $9 million of the total $9.5 million “Corps/Bureau Transmission” charge in BP-22.
- Ownership transfer will change the cost assignment.
- There are two main cost groupings:
  - Operations and maintenance
  - Capital-related costs (e.g. interest, depreciation, Minimum Required Net Revenues)

Grand Coulee: Treatment of O&M

- The phased transition of Transmission taking over O&M creates options.
  1. Do not forecast any change in the O&M component of the BBL charge
     - BPA would continue to calculate an O&M cost for the BBL charge, as if the transfer did not occur
     - As Transmission takes over O&M functions, the BBL charge would be recalculated during the rate period (new method needed).
  2. Forecast phase-in of O&M when calculating the BBL charge
     - BPA would calculate an O&M cost for the BBL charge as if the transfer did not occur.
     - The cost would be adjusted based on assumptions about the timing of the transfer of O&M responsibility. For example, reduce it by 1/3 per year over the rate period.
- The staff preference is Option 2.
  – Far simpler: avoids need to track during the rate period and doing a "true-up" of the BBL charge

($000s)	2026	2027	2028
O&M without ownership change	9,249	11,942	11,725
Transition rate	66%	33%	0%
O&M charged	6,104	3,941	-

Grand Coulee: Treatment of Debt

- Along with the asset, we intend to transfer some Power debt to Transmission.
  - Bonneville takes a portfolio approach to debt management.
  - Debt is generally not directly tied to assets.
  - The debt to asset (leverage) ratio is our best representation of the relationship between debt and the net value of Bonneville's assets.
  - This approach is consistent with how the BBL charge is constructed, which includes estimates of interest expense.
- Bonneville proposes to transfer an amount of debt from Power to Transmission equal to the net book value times Power's most recent debt to asset ratio.
  - Example: $119 million estimated net book value X 85.4% (FY23 ratio) = $101 million of debt
  - Initial proposal will use the latest FY24 leverage forecast.
  - Final Proposal will incorporate actual values.

Grand Coulee: Impact on BP-26

- The BBL charge to Transmission will be lower but it will see somewhat higher direct costs, e.g. O&M, debt service.
- Power will receive less revenue from the BBL charge but will also see somewhat lower direct costs.
- The segmentation of the transferred facilities may change.
- The future impact on segmentation is uncertain now because the transfer will not occur in time to be incorporated in the BP-26 initial proposal segmentation study.
- For the initial proposal, we propose that the transferred assets remain in their BP-22 segments. This is accomplished by treating the transfer as a new capital addition in the “plant model” which calculates depreciation and provides the forecast segmented investment base for the revenue requirement.
- Any revisions to plant segment assignments would appear in the final proposal segmentation study and segmented revenue requirement.

Income Statement & Cash Flow Tables

Revenue Requirement Assumptions

- All data is of IPR vintage and should be considered preliminary.
- Data will be refreshed for the Initial Proposal.
- Modeled costs.
  - Costs modeled in the rate case, such as power purchases, gen inputs, generation integration, and transmission acquisition, have not been modeled in this dataset.
  - These costs are calculated in the rate development process.

Repayment

- Repayment model methodology is consistent with past practice.
- Capital financing: Treasury bonds, Appropriations for CRFM, revenue financing as proposed.
- Treasury debt placement: all bonds in the rate period are assumed to be issued in the fourth quarter of each fiscal year.
- Regional Cooperation Debt (RCD): all RCD2 transactions are forecast and embedded in repayment results. RCD2 bonds due by 2044.
- CGS new investment debt: bonds issued in 2026-2028 due by 2044. Bonds issued after the rate period may have maturities to 2063.
- Interest rates: uses FY24 forecast. May be updated for Final Proposal.
- Repayment results will be updated for the Initial and Final proposals using the most up-to-date data available and assumptions.

Draft Transmission Income Statement

	($000s)	A 2026	B 2027	C 2028	D Average	E BP-24 Average
1	OPERATING EXPENSES					
2	TRANSMISSION OPERATIONS	227,407	247,420	265,169	246,665	194,970
3	TRANSMISSION ENGINEERING	73,817	77,373	80,793	77,327	60,713
4	TRANSMISSION MAINTENANCE INCLUDING ENVIRONM	217,704	229,894	241,637	229,745	196,221
5	TRANSMISSION ACQ & ANCILLARY SERVICES		**Modeled in Rate Case**			
6	BPA INTERNAL SUPPORT	203,851	220,629	231,593	218,691	137,999
7	OTHER INCOME, EXPENSES & ADJUSTMENTS	-	-	-	-	-
8	DEPRECIATION & AMORTIZATION	378,690	405,946	434,971	406,536	350,978
9	TOTAL OPERATING EXPENSES	1,101,469	1,181,261	1,254,163	1,178,964	940,881
10						
11						
12	INTEREST EXPENSE					
13	INTEREST EXPENSE					
14	FEDERAL APPROPRIATIONS	-	-	-	-	-
15	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)	(18,968)	(18,968)	(18,968)
16	ON LONG-TERM DEBT	186,989	225,334	266,999	226,441	131,651
17	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559	527	548	559
18	DEBT SERVICE REASSIGNMENT INTEREST	-	-	-	-	422
19	NON-FEDERAL INTEREST (INCL CUSTOMER FUNDED)	69,540	66,552	65,895	67,329	61,968
20	PREMIUMS/DISCOUNTS	-	-	-	-	-
21	AFUDC	(42,527)	(44,434)	(43,337)	(43,432)	(14,517)
22	INTEREST INCOME	(11,614)	(11,459)	(11,734)	(11,602)	(2,189)
23	NET INTEREST EXPENSE	183,979	217,584	259,383	220,315	158,924
24						
25	TOTAL EXPENSES	1,285,448	1,398,845	1,513,546	1,399,279	1,099,805
26						
27	TOTAL MINIMUM REQUIRED NET REVENUE 1/	128,094	128,172	128,013	128,093	54,737
28	PLANNED NET REVENUES FOR RISK	-	-	-		-
29	TOTAL PLANNED NET REVENUE	128,094	128,172	128,013	128,093	54,737
30						
31	TOTAL REVENUE REQUIREMENT	1,413,541	1,527,017	1,641,558	1,527,372	1,154,543

Draft Transmission Statement of Cash Flows

	($000s)	A 2026	B 2027	C 2028	D Average	E BP-24 Average
1	CASH FROM CURRENT OPERATIONS:					
2	MINIMUM REQUIRED NET REVENUE	128,094	128,172	128,013	128,093	54,737
3	EXPENSES NOT REQUIRING CASH:					
4	DEPRECIATION & AMORTIZATION	378,690	405,946	434,971	406,536	350,978
5	CUSTOMER FUNDED PROJECTS NET INTEREST	5,046	3,677	2,389	3,704	3,287
6	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559	527	548	559
7	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)	(18,968)	(18,968)	(18,968)
8	NON-CASH REVENUES					
9	CUSTOMER FUNDED	(54,360)	(67,096)	(55,439)	(58,965)	(25,307)
10	AC INTERTIE CO/FIBER	(3,568)	(3,568)	(3,568)	(3,568)	(3,658)
11	CASH PROVIDED BY CURRENT OPERATIONS	435,493	445,550	484,811	455,285	361,629
12						
13	CASH USED FOR CAPITAL INVESTMENTS:					
14	INVESTMENT IN:					
15	UTILITY PLANT	(1,244,400)	(1,407,100)	(1,299,800)	(1,317,100)	(565,739)
16	CASH USED FOR CAPITAL INVESTMENTS	(1,244,400)	(1,407,100)	(1,299,800)	(1,317,100)	(565,739)
17						
18	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:					
19	INCREASE IN LONG-TERM DEBT	1,119,400	1,282,100	1,174,900	1,192,133	510,739
20	DEBT SERVICE REASSIGNMENT PRINCIPAL	-	-	-	-	(8,820)
21	REPAYMENT OF CAPITAL LEASES	(114,472)	(92,058)	(81,225)	(95,918)	(101,584)
22	REPAYMENT OF LONG-TERM DEBT	(196,021)	(231,664)	(281,799)	(236,495)	(196,225)
23	REPAYMENT OF CAPITAL APPROPRIATIONS	-	-	-	-	-
24	CASH FROM TREASURY BORROWING AND APPROP.	808,907	958,378	811,876	859,721	204,110
25						
26	ANNUAL INCREASE (DECREASE) IN CASH	-	-	-	-	-
27	PLANNED NET REVENUES FOR RISK	-	-	-	-	-
28	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	-	-	-	-	-

Draft Power Income Statement

	($000s)	A 2026	B 2027	C 2028	D Average	E BP24 Average
1	OPERATING EXPENSES					
2	POWER SYSTEM GENERATION RESOURCES					
3	OPERATING GENERATION RESOURCES	869,280	969,510	973,258	937,349	774,022
4	OPERATING GENERATION SETTLEMENT PAYMENTS	59,303	59,993	60,705	60,001	27,625
5	NON-OPERATING GENERATION	2,700	2,760	2,822	2,761	2,358
6	CONTRACTED POWER PURCHASES	Modeled in Rate Case				
7	AUGMENTATION POWER PURCHASES	0	0	0	0	0
8	EXCHANGES & SETTLEMENTS	286,000	286,000	286,000	286,000	274,799
9	RENEWABLE GENERATION	24,112	12,412	2,212	12,912	26,367
10	GENERATION CONSERVATION	126,965	127,014	127,020	127,000	113,712
11	POWER NON-GENERATION OPERATIONS	83,552	88,160	90,649	87,454	83,162
12	PS TRANSMISSION ACQUISITION AND ANCILLARY SERVICES	Modeled in Rate Case				
13	F&W/USF&W/PLANNING COUNCIL	337,680	344,127	354,130	345,312	313,757
14	GENERAL AND ADMINISTRATIVE/SHARED SERVICES	159,898	171,587	178,328	169,938	114,613
15	OTHER INCOME, EXPENSES AND ADJUSTMENTS	0	0	0	0	0
16	DEPRECIATION	148,432	152,057	155,696	152,062	141,652
17	AMORTIZATION	326,696	298,931	310,357	311,995	314,276
18	ACCRETION	42,607	44,438	46,350	44,465	40,921
19	TOTAL OPERATING EXPENSES	2,467,225	2,556,991	2,587,526	2,537,247	2,227,264
20						
21	OTHER EXPENSE AND (INCOME)					
22	INTEREST					
23	APPROPRIATED FUNDS	27,969	29,294	27,970	28,411	28,720
24	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)	(45,937)	(45,937)	(45,937)
25	BONDS ISSUED TO U.S. TREASURY	38,757	35,123	35,540	36,473	41,694
26	BOND PREMIUMS/DISCOUNTS	0	0	0	0	5,848
27	NON-FEDERAL INTEREST	252,292	252,828	251,439	252,186	232,540
28	AMORTIZATION OF NON-FEDERAL PREMIUMS/DISCOUNTS	(37,496)	(38,680)	(39,440)	(38,539)	(36,386)
29	AMORTIZATION OF COST OF ISSUANCE	208	308	408	308	500
30	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	(20,002)	(20,295)	(20,498)	(20,265)	(17,979)
31	INTEREST CREDIT ON CASH RESERVES	(23,586)	(23,000)	(22,630)	(23,072)	(3,943)
32	INTEREST INCOME ON DECOMMISSIONING TRUST	(16,849)	(17,824)	(18,855)	(17,842)	(11,830)
33	OTHER INCOME (NET)	0	0	0	0	(4,471)
34	TOTAL OTHER EXPENSE AND (INCOME)	175,355	171,816	167,997	171,723	188,752
35						
36	TOTAL EXPENSES	2,642,580	2,728,807	2,755,523	2,708,970	2,416,016
37						
38	MINIMUM REQUIRED NET REVENUE 1/	153,212	150,029	310,984	204,742	155,242
39	PLANNED NET REVENUE FOR RISK	0	0	0	0	129,000
40	PLANNED NET REVENUE, TOTAL (38+39)	153,212	150,029	310,984	204,742	284,242
41						
42	**TOTAL REVENUE REQUIREMENT**	**2,795,792**	**2,878,836**	**3,066,507**	**2,913,711**	**2,700,259**

Draft Power Statement of Cash Flows

	($000s)	A 2026	B 2027	C 2028	D Average	E BP24 Average
1	CASH FROM OPERATING ACTIVITIES					
2	MINIMUM REQUIRED NET REVENUE 1/	153,212	150,029	310,984	204,742	155,242
3	NON-CASH ITEMS:					
4	NON-FEDERAL INTEREST	3,329	2,064	740	2,045	5,116
5	DEPRECIATION AND AMORTIZATION	475,127	450,988	466,053	464,056	455,928
6	ACCRETION	42,607	44,438	46,350	44,465	40,921
7	NON-CASH EXPENSES	(16,849)	(17,824)	(18,855)	(17,842)	(16,302)
8	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)	(45,937)	(45,937)	(45,937)
9	NON-CASH REVENUES	(30,600)	(30,600)	(30,600)	(30,600)	(30,600)
10	AMORTIZATION OF P2IP SETTLEMENT	28,122	28,122	28,122	28,122	N/A
11	AMORTIZATION OF NON-FEDERAL PREMIUMS/DISCOUNTS	(37,496)	(38,680)	(39,440)	(38,539)	(36,386)
12	AMORTIZATION OF COST OF ISSUANCE	208	308	408	308	500
13	CASH CONTRIBUTION TO DECOMMISSIONING TRUST FUNDS	(15,700)	(16,300)	(17,000)	(16,333)	(15,100)
14	PAYMENTS FOR LITIGATION STAY AGREEMENTS	(21,200)	(21,687)	(22,158)	(21,682)	8,800
15	CASH PROVIDED BY OPERATING ACTIVITIES	534,823	504,921	678,666	572,804	522,182
16						
17	CASH FROM INVESTMENT ACTIVITIES					
18	INVESTMENT IN:					
19	UTILITY PLANT (INCLUDING AFUDC)	(389,709)	(346,010)	(347,978)	(361,232)	(277,548)
20	FISH & WILDLIFE	(32,207)	(60,187)	(49,486)	(47,293)	(41,000)
21	CASH USED FOR INVESTMENT ACTIVITIES	(421,916)	(406,197)	(397,464)	(408,525)	(318,548)
22						
23	CASH FROM BORROWING AND APPROPRIATIONS:					
24	INCREASE IN BONDS ISSUED TO U.S. TREASURY	333,392	361,493	352,785	349,223	271,484
25	REPAYMENT OF BONDS ISSUED TO U.S. TREASURY	(427,031)	(380,467)	(354,067)	(387,188)	(209,032)
26	INCREASE IN FEDERAL CONSTRUCTION APPROPRIATIONS	51,524	4,704	4,679	20,302	13,048
27	REPAYMENT OF FEDERAL CONSTRUCTION APPROPRIATIONS	(13,969)	(38,533)	(237,934)	(96,812)	(243,968)
28	REPAYMENT OF NON-FEDERAL OBLIGATIONS	(36,161)	(39,551)	(35,031)	(36,915)	(24,130)
29	CUSTOMER PROCEEDS	0	0	0	0	0
30	PAYMENT OF IRRIGATION ASSISTANCE	(20,662)	(6,370)	(11,634)	(12,889)	(11,037)
31	CASH PROVIDED BY BORROWING AND APPROPRIATIONS	(112,908)	(98,725)	(281,202)	(164,278)	(203,635)
32						
33	ANNUAL INCREASE (DECREASE) IN CASH	0	0	0	0	0
34						
35	PLANNED NET REVENUE FOR RISK	0	0	0	0	129,000
36						
37	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	0	0	0	0	129,000

1/ Minimum required net revenues are added to ensure suffcient cash flow is available to repay the federal investment.

Interconnection Credits (GI and Non-GI)

Interconnection Credit Background

- Interconnection deposits are considered advanced payment of future revenues. The deposited funds are used for construction or upgrades to network facilities. Advanced funds earn interest from the day of deposit and for the duration of the repayment period. The customer receives a transmission credit until the deposit is repaid or forfeit at the end of the repayment period.
  - Direct assigned interconnection facilities are not eligible for transmission credits
  - Expediting costs are not eligible for Credits

Interconnection Credit Background

- The net effect of Interconnection Credits appears in three places in the revenue requirement. The sum of all three, the net effect on the revenue requirement, is equal to the total credit.

Interconnection Credits Effect on Revenue Requirement =

(1) Interest accrued on outstanding deposit balances

(2) Depreciation on the assets

(3) Minimum Required Net Revenues (MRNR = revenue credit minus #1 & #2)

- Generally, credits are repaid in a shorter timeframe than the useful life of the assets. Credits tend to be repaid in 5-12 years while the assets may have much longer service lives.

Credit Policies

- Interconnection credits are managed under two Business Practice policies:
  - Generator Interconnection (see GI Transmission Credits Business Practice)
    - SGI/LGI
  - Non-GI (see Transmission Credits for Non-GI Transmission Upgrades Business Practice)
    - LLI
- Each policy has its own unique requirements that must be considered in developing the forecast.

GI vs. Non-GI Credit Plans

	GI	Non-GI
Repayment Rate	Dollar-for-dollar at current rate for reserved Transmission Service (Method 1) or Generator Nameplate * Capacity Factor * Current Rate (Method 2)	Metered Incremental POD Demand per Credit Agreement (NT), or Eligible Incremental Transmission Service (PTP)
Repayment Term	20 Year	
Interest Rate	USD Government Agency BVAL Curve	
Start Date	Transmission Service Commencement Date (Method 1) or Commercial Operation Date in LGIA/SGIA (Method 2)	Energization Date of Network Upgrades
20-Year Balance	Cash refund (Tariff Requirement)	Forfeit

Transmission Credits - Forecast Process

- The Generation Interconnection (GI) and Line and Load Interconnection (LLI) Queues are assessed to determine which projects have a high likelihood to be completed prior to or during the upcoming rate period.
- To the extent possible, projects are tied to a request(s) in the Transmission Queue to forecast sales eligible to receive Transmission Credits.
- When a request in the queue cannot be tied to a request(s) in the Transmission Queue, a percentage of the nameplate is used to forecast the sales eligible to receive credits based on historical models.
  - 30% - Year 1
  - 50% - Year 2
  - 70% - Year 3
- For NT LLI requests, a load shape is applied to the forecast for the project.
- The dollar value of the Transmission Credits is forecasted based upon historical transmission credit averages, TSRs at the LT PTP rate, or projected new generation/load.
- Interest expense is calculated based on the applicable interest rate at the time of deposit or, for forecast deposits, based on the average interest rates of the most recent 12-month period.

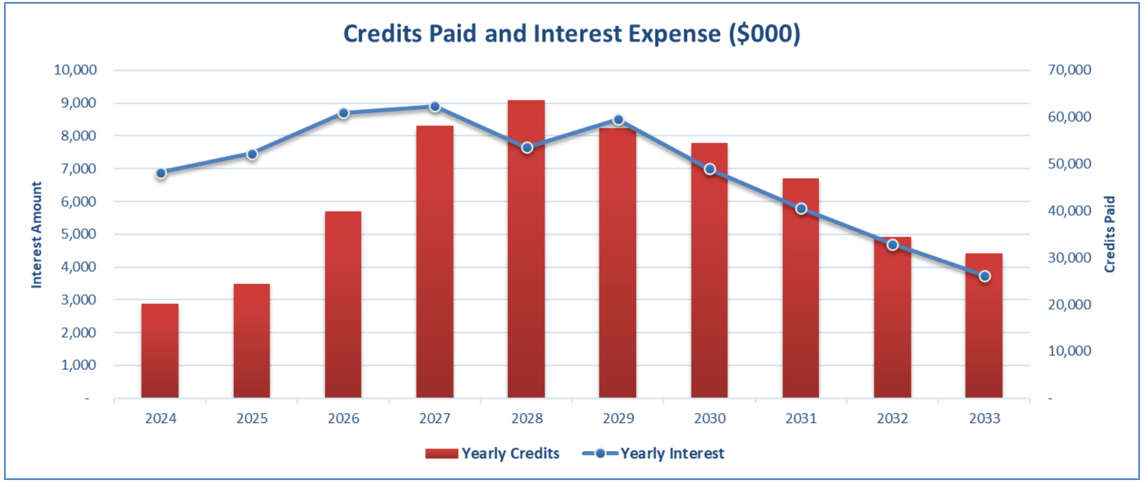
BP-26 Preliminary Forecast Results

- BPA currently holds $276 million in funds advanced for Network Upgrades. Of this total:
  - $96 million is currently in the repayment period, with customers actively receiving Transmission Credits
  - $180 million is pending project completion and are accruing interest.
- For the BP-26 rate period, BPA is forecasting approximately $210 million in additional funds to be advanced for Network Upgrades for continuing and future interconnection projects.
- The average transmission credit is $53.9 million per year in FY 26-28.
- The average interest expense is $8.4 million per year in FY 26-28.

BP-26 Credit and Interest Forecast Comparison

BP-26 Rate Case Comparison Forecasts

		BP-24		BP-24		BP-26			BP-26	Avg Increase	%
	2023	2024	2025	AVG	2025	2026	2027	2028	AVG	(BP-26 less BP-24)	Increase
Forecasted Credit ($000)	21,487	24,112	26,501	**25,307**	24,402	39,954	58,125	63,702	**53,927**	**22,512**	**113%**
Forecasted Interest ($000)	4,251	3,656	2,918	**3,287**	7,458	8,705	8,905	7,656	**8,422**	**4,573**	**156%**



Next Steps

- Comments or questions? Email techforum@bpa.gov and copy your Account Executive.
- Please provide comments by September 11.

Meeting Wrap Up and Next Steps

- Please send any feedback, with your topic you are addressing by to BPA's Tech Forum at techforum@bpa.gov, **by September 11**, with a cc to your Power and/or Transmission Account Executive.
- The final workshop will be on September 25, and it will be hybrid.

BP-26 and TC-26 Workshop

August 27-28, 2024

Day 2

Agenda August 27 (Day 1)

BP/TC-26 Pre-Proceeding Workshop		
Time*	Topic	Presenter
9:00 – 9:05 a.m.	Introduction, Meeting Protocols, Comments and Agenda	Brian McConnell
9:10 – 9:25 a.m.	Power Rates – Natural Gas Price Forecast	Aimee Robinson
9:30 – 10:15 a.m.	Generation Inputs Capacity Costs	Jonathan Ramse, Matthew Pham, Garth Beavon
10:15 – 10:30 a.m.	**Break**	
10:30 – 12 p.m.	Power and Transmission Risk	Zach Mandell
12 – 1 p.m.	**Lunch**	
1 – 2:15 p.m.	Revenue Financing	Ethan Postrel
2:15 – 3 p.m.	Power and Transmission Revenue Requirement	Alex Lennox, Tracy Carlson, Quay Rubin
3:05 – 3:30 p.m.	Interconnection Credits (GI and Non-GI)	Paul Hermanson
	Closing Remarks	

**** Times are approximate***

Agenda August 28 (Day 2)

BP/TC-26 Pre-Proceeding Workshop		
Time*	Topic	Presenter
9:00 – 9:05 a.m.	Introduction, Meeting Protocols, Comments and Agenda	Brian McConnell
9:10 – 9:30 a.m.	Power Rates – Transfer Service Delivery Charge	Jason Boen
9:35 – 9:45 a.m.	Energy Storage Devices	Eric King, Frank Puyleart
9:50 – 10:50 a.m.	Generation Inputs Rates	Bill Hendricks, Nancy Morales, Frank Puyleart
10:55 – 11 a.m.	**Break**	
11 a.m. – 12 p.m.	GI Withdrawal Penalties	Rebecca Fredrickson, Bill Hendricks, Rahul Kukreti
12:00 – 1 p.m.	**Lunch**	
1:00 – 1:30 p.m.	GI Reforms – LGIA Update and Status of BPA Option to Build	Kim Gilliland, Katie Sheckells
1:35 – 1:55 p.m.	Draft Proposed Tariff (redline), including Tariff Clean up (ministerial edits to Attachments L and R)	Melanie Bersaas, Colleen McDonnell
2 – 2:15 p.m.	TC-26 Settlement – Proposed Initiation and Next Steps	Brian McConnell, Melanie Bersaas
	Closing Remarks	

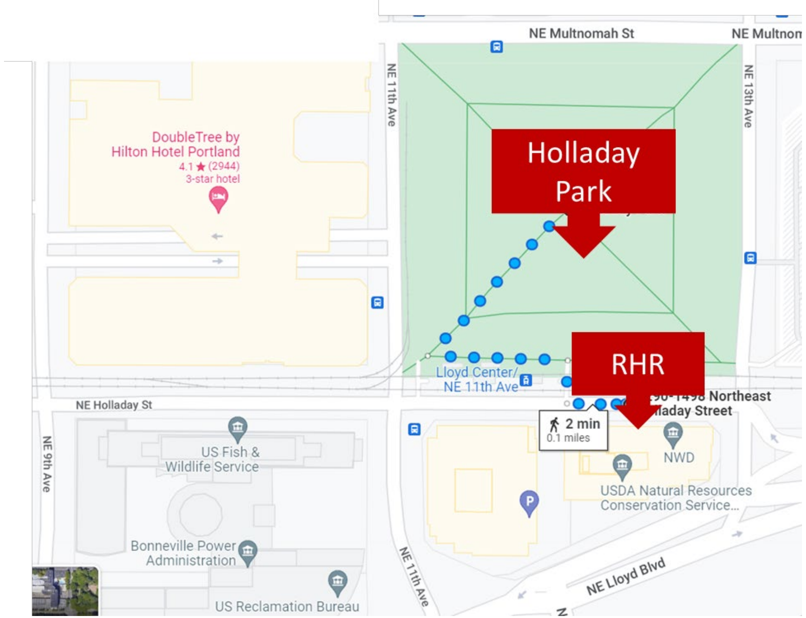
**** Times are approximate***

Webex Format Update

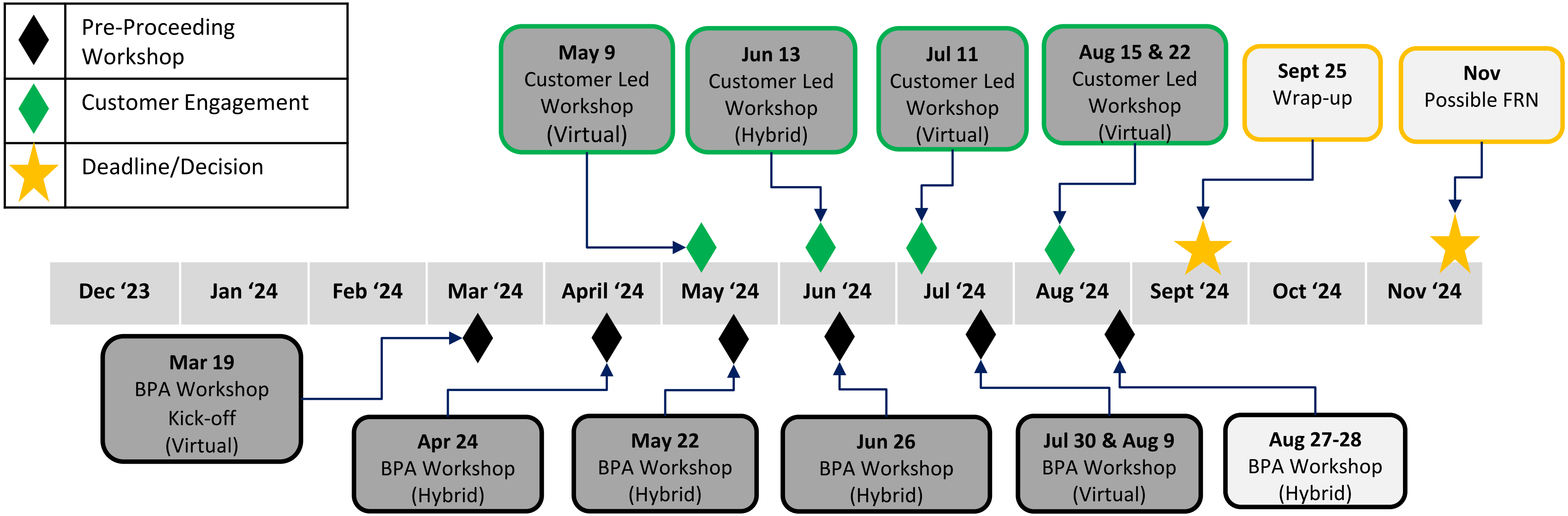
- BPA has adjusted its public stakeholder virtual engagement approach.
- The Webex format is moving to a “webinar” style.
  - Webex attendees can no longer mute/unmute themselves or enable their webcam.
- The all-chat feature is disabled. Attendees can only message panelists.
  - To participate, attendees must raise their hand (BPA will unmute you to enable your participation), or send a question to panelists in the chat.
- If you are Webex by phone only: press *3 to request to be unmuted.
- Moderators will continue to address raised hands in the order received.
  - Please continue to state your name and affiliation.
- As necessary, BPA may evolve these procedures and take other measures at its discretion to prevent future disruptions.

Safety Moment

- The Rates Hearing Room has two exits.
- In the event an alarm sounds, please meet at Holladay Park across the street.



Proposed BP/TC-26 Pre-Proceeding Workshop Schedule



Procedural schedule dates are draft only

Approach to Customer Engagement

- Most identified issues will be presented according to the following process at workshops (multiple steps might be addressed in a single workshop):

Phase One: Approach Development	Phase Two: Evaluation	Phase Three: Proposal Development
Step 1: Introduction & Education	**Step 3: Analyze the Issue**	**Step 5: Discuss Customer Feedback**
Step 2: Description of the Issue	**Step 4: Discuss Alternatives**	**Step 6: Staff Proposal**

Teams will follow the steps that may be covered in one workshop or more based on the complexity of the issue.

Customer Comment Process

- Thank you to everyone who submitted comments on the July 30 and Aug. 9 workshop topics.
- BPA is using the same comment tracking and response process that was developed in BP/TC-24, which includes the following:
  - All customer comments will be posted to the BP-26 Rate Case website.
  - BPA will create a consolidated customer response (CCR) document for each workshop that will be posted/updated at the same time as other workshop materials.
  - The CCR is organized to address comments listed by the workshop date where the comments were received.
  - The CCR will provide direct responses or identify other forums or future BP/TC-26 workshops where BPA expects to provide a response.
    - To the extent possible, BPA will endeavor to provide responses prior to the next workshop in the Customer Comments section on the BP-26 website (updated CCR will be posted with workshop materials)
    - All comments will have a response

July Customer Led Workshop

- During the July 11 BP-26 Customer-Led Workshop, two topics were discussed
  - Short Distance Discount
    - An examination of the Short-Distance Discount for NT service and PTP customers is something that we are not able to accommodate within the scope of BP-26. BPA does see value in the discussion and would be amenable to opening the subject in future rates cases.
  - Utility Delivery Roll In
    - BPA intends to bring a proposal during the September workshop.

Transfer Service

Transfer Service

BPA's Transfer Service group acquires transmission across third-party transmission systems for service to loads outside Bonneville's Balancing Authority Area. The current annual cost to provide this service to all transfer customers is roughly $90 million.

The following slides look at the rates that impact Transfer Service customers:

- Transfer Service Operating Reserve Charge
- Transfer Service Regulation and Frequency Response Charge
- Transfer Service Delivery Charge (TSDC).
- Transfer Service Regional Compliance Enforcement Charge.

Transfer Service Operating Reserve Charge

- Transfer Service Operating Reserve Rate – no changes from previous rate case
  - The rate for the Transfer Service Spinning Operating Reserve Charge shall be equal to the ACS-26 Operating Reserve – Spinning Reserve Service rate.
  - The rate for the Transfer Service Supplemental Operating Reserve Charge shall be equal to the ACS-26 Operating Reserve – Supplemental Reserve Service rate.

Transfer Service Regulation and Frequency Response Charge

- Transfer Service Regulation and Frequency Response Rate – no changes from previous rate case.
  - The rate for the Transfer Service Regulation and Frequency Response Charge shall be equal to the ACS-26 Regulation and Frequency Response.

Transfer Service Delivery Charge (TSDC) Rate

- Current TSDC rate is $1.117/kW
- Estimated TSDC for BP-26 is $1.17/kW
- This is an **increase of approximately 4%**
- The rate increase is mainly due to slightly higher costs BPA is incurring from providers for energy delivered over non-Federal low voltage facilities.

Transfer Service Regional Compliance Enforcement Charge

- BPA charges the Transfer Service Regional Compliance Enforcement Rate (TSRCE) to customers served by transfer to recover WECC-related costs for loads located on the systems of third-party transmission providers.

- When applying the same rounding as done to establish the Regional Compliance Enforcement within BPA's Transmission Rates, Transfer Service comes up with 0.05 mills/kWh, the same as BP-24.

ACS Design for Energy Storage Devices

ACS Rates for ESDs

- Customer comments ranged from support for an ACS rate for ESDs, to encouragement for BPA to maintain the status quo for BP-26 and not develop a use-based capacity charge for ESDs until there is more certainty around ESD interconnection and operations.
- BPA believes that as ESDs interconnect to the BPA system, BPA will need an ACS rate and service design to provide balancing service for ESDs.
- However, after careful consideration of customer comments as well as review of ESDs requests and timing in the BPA queue, BPA staff is recommending that for BP-26, BPA maintain the status quo.
  - BPA will include language in the initial proposal regarding the need for an ACS rate for ESDs.
  - If the pace of installation of ESDs in BP-26 justify it, BPA may initiate a stand-alone mini-7(i) process to develop an ACS charge for ESDs.

Preliminary Generation Inputs Rates

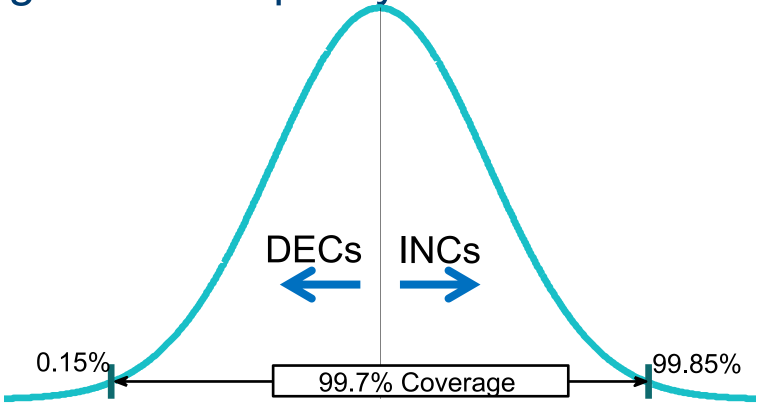
Preliminary BP-26 Rates

Rate	Units	BP-24 Rates	BP-26 Rates	Percent Change
RFR				
Regulation and Frequency Response	mills/kWh	0.44	0.45	2.3%
OR				
Operating Reserves - Spinning	mills/kWh	11.05	15.93	44.2%
OR - Spinning Default	mills/kWh	12.71	18.32	44.1%
Operating Reserves - Supplemental	mills/kWh	7.22	9.48	31.3%
OR - Supplemental Default	mills/kWh	8.30	10.90	31.3%
DERBS				
DERBS Inc	mills/kWh	21.30	74.30	248.8%
DERBS Dec	mills/kWh	1.24	0.00	-100.0%
VERBS				
VERBS Wind Regulating	mills/kW-mo	0.36	0.41	14.5%
VERBS Wind Non-Regulating	mills/kW-mo	0.40	0.36	-8.9%
VERBS Solar Regulating	mills/kW-mo	0.28	1.76	524.1%
VERBS Solar Non-Regulating	mills/kW-mo	0.17	0.99	469.0%

Balancing Reserve Forecast

Balancing Reserve Methodology

- BPA holds capacity for balancing reserves to meet the NERC standards and OATT requirements to maintain load-resource balance within its balancing authority area.
- Balancing reserves needed for the BPA BAA are set in advance of the start of each rate period.
- BPA performs statistical evaluations of combined load and generation fleet error to yield a final amount of balancing reserve capacity needed to meet BPA's 99.7% planning standard.
- This evaluation captures balancing authority diversity benefits, the difference in timing of INCs and DECs deployed for generators and load.



Balancing Reserve Components in the Energy Imbalance Market

- BPA defines balancing reserve capacity as a combination of “regulation” and “non-regulation” capacity to promote consistency with definitions in the EIM.
  - Regulation Capacity (Reg)
    - The difference between actual Load net Generation and the net EIM dispatch operating target (DOT) of Load net Generation
  - Non-Regulation Capacity (Non-Reg)
    - The difference between the net EIM dispatch operating target (DOT) of Load net Generation and expected hourly schedule of Load net Generation
    - BPA makes its Non-Reg portion of its balancing reserve available to the EIM by bidding or designating as Available Balancing Capacity (ABC)

Preliminary BP-26 Reserve Forecast

Rate Case Average	Wind Capacity (MW)	Solar Capacity (MW)	Total INC Bal. Res. (MW)	Total DEC Bal. Res. (MW)
BP-22	3,028	166	705	-852
BP-24	3,096	318	743	-888
BP-26	3,695	1,794	1,127	-1,200

Rate Case Average	Wind Res. (MW)	Solar Res. (MW)	Load Res. (MW)	Fed Res. (MW)
BP-22	367	12	293	23
BP-24	373	34	302	21
BP-26	437	348	304	22

Rate Case Average	Wind Reserves (% Nameplate)	Solar Reserves (% Nameplate)
BP-22	12.1%	7.5%
BP-24	12.2%	10.6%
BP-26	11.8%	19.4%

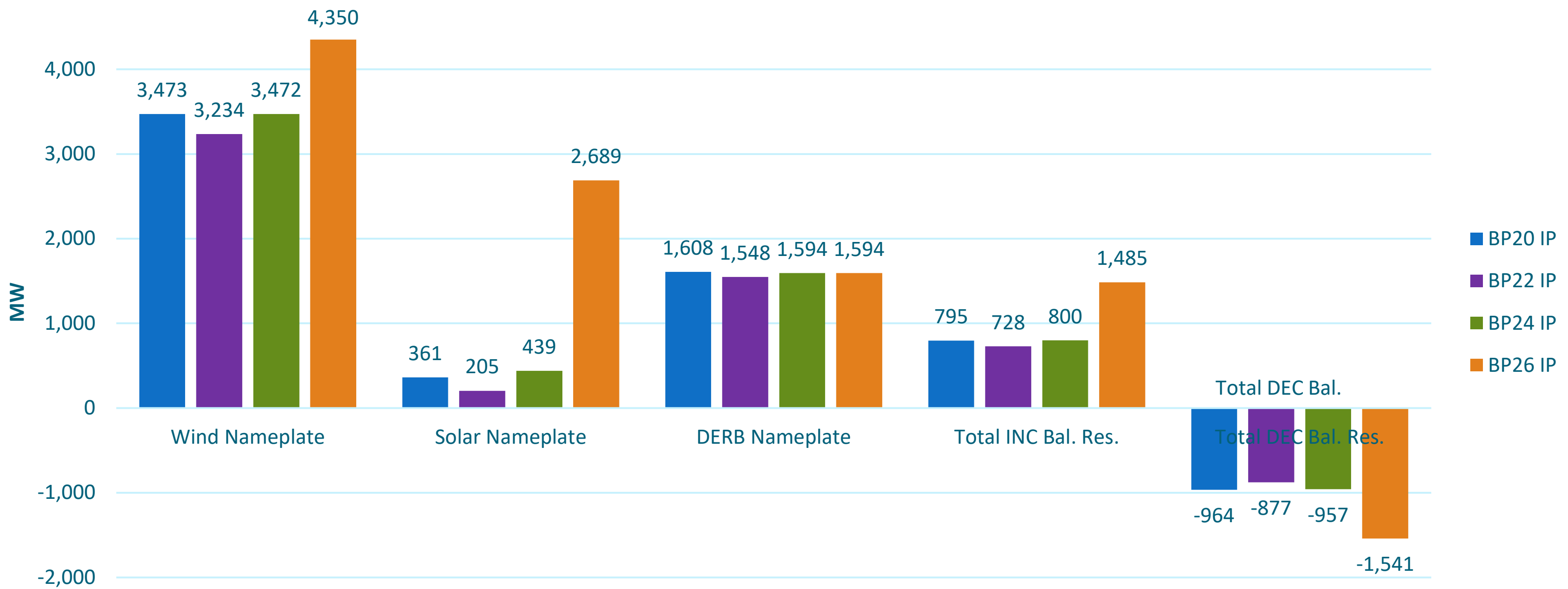
Preliminary BP-26 Capacity Forecast

Month	Wind Capacity (MW)	Solar Capacity (MW)	Total INC Balancing Reserves (MW)	Total DEC Balancing Reserves (MW)
Oct ‘25	2,830	239	707	-805
Apr ‘26	3,194	849	764	-864
Sep ‘26	3,586	1,209	890	-997
Dec ‘26	3,786	1,689	1,039	-1,117
Oct ‘27	3,990	2,509	1,388	-1,438
Dec ‘27	4,350	2,649	1,466	-1,526
Sep ‘28	4,350	2,689	1,485	-1,541
BP-26 Avg	3,695	1,794	1,127	-1,200

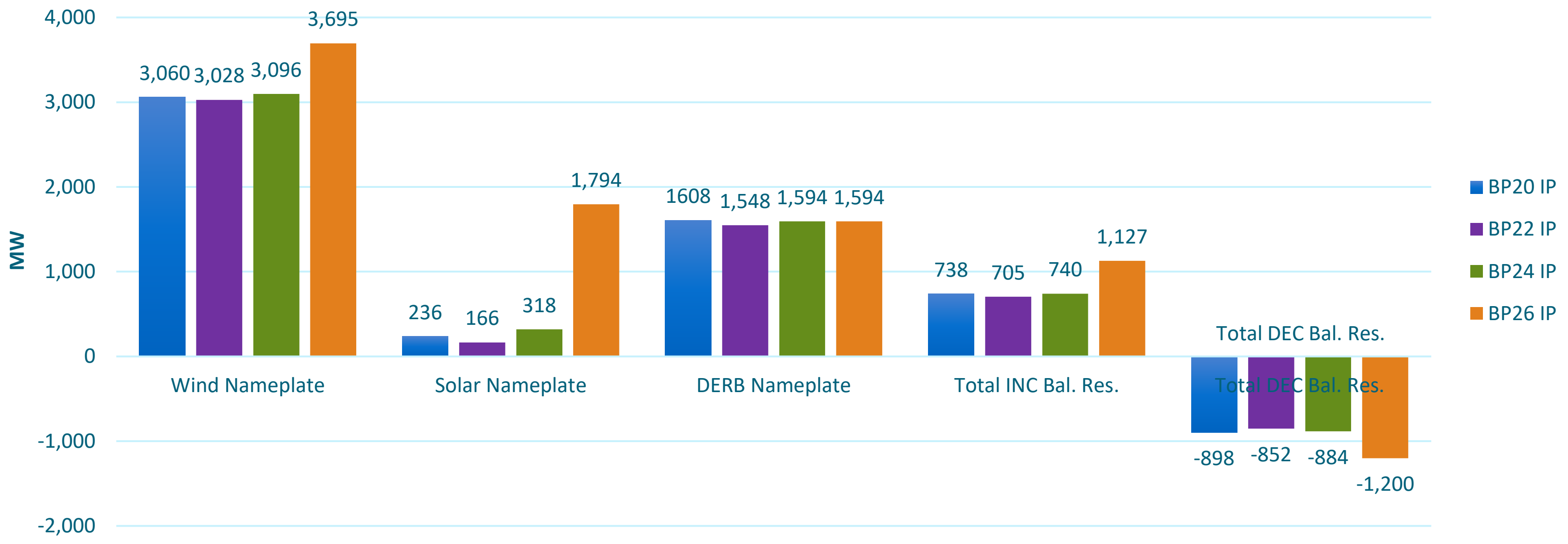
Preliminary BP-26 Reserve Forecast

Month	Wind INC Reserves (MW)	Solar INC Reserves (MW)	DERs INC Reserves (MW)	Load INC Reserves (MW)	Fed INC Reserves (MW)
Oct ‘25	309	22	13	341	22
Apr ‘26	325	118	11	291	19
Sep ‘26	383	204	11	271	18
Dec ‘26	411	321	12	272	20
Oct ‘27	505	508	14	333	24
Dec ‘27	553	547	14	325	23
Sep ‘28	553	557	14	328	24
BP-26 Avg	437	348	13	304	22

Generation vs Reserves at the end of the Rate Period



Average Generation vs Reserves for Past Rate Cases



% Nameplate

Rate Case Average	Wind Capacity (MW)	Wind Res. (MW)	Wind Reserves (% Nameplate)
BP-22	3,028	367	12.1%
BP-24	3,096	373	12.1%
BP-26	3,695	437	11.8%

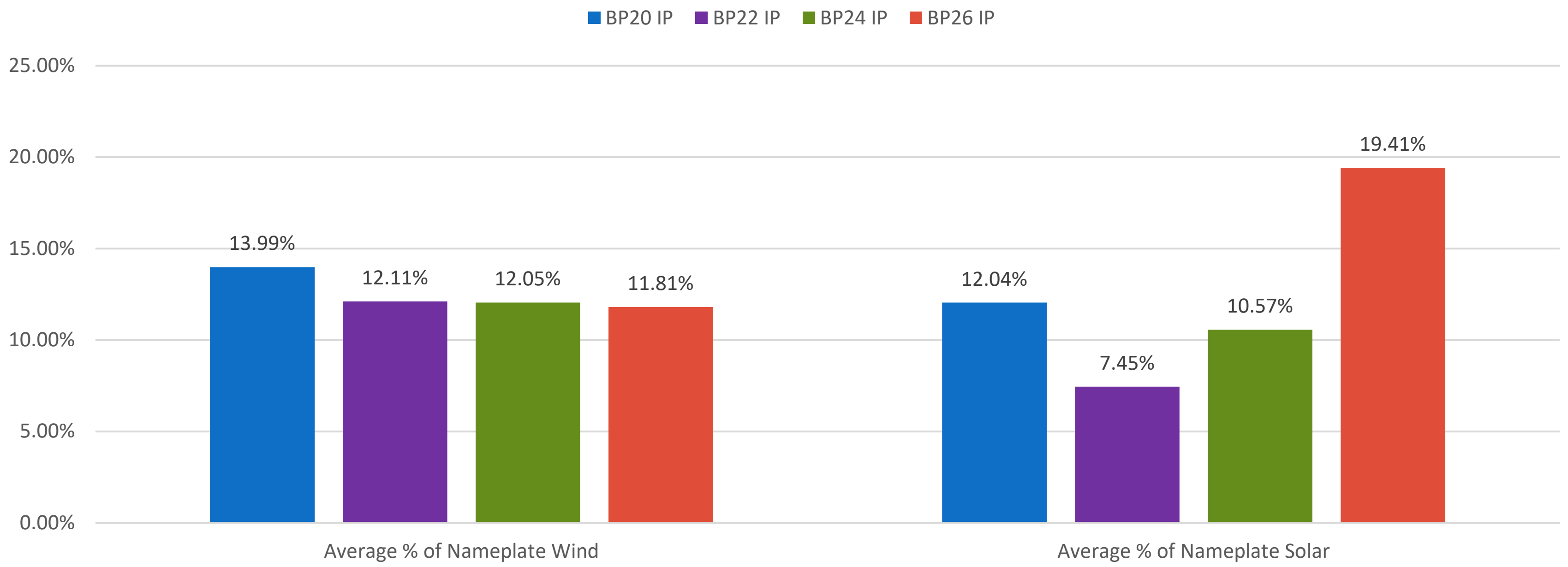
Rate Case Average	Solar Capacity (MW)	Solar Res. (MW)	Solar Reserves (% Nameplate)
BP-22	166	12	7.5%
BP-24	318	34	10.6%
BP-26	1,794	348	19.4%

- % Nameplate calculation

$$\%Nameplate = \frac{Generation\ Reserves\ (MW)}{Generation\ Capacity\ (MW)} * 100$$

- Rates for wind and solar use % Nameplate as a billing determinate for Variable Energy Resources.
  - Rates for wind and solar have been the same since BP-22.

% Nameplate by Rate Case



Preliminary BP-26 Reserve Forecast

Month	Wind INC Res. (% Nameplate)	Solar INC Res. (% Nameplate)
Oct '25	10.9%	9.1%
Apr '26	10.2%	16.9%
Sep '26	10.7%	16.9%
Dec '26	10.8%	19.0%
Oct '27	12.7%	20.3%
Dec '27	12.7%	20.6%
Sep '28	12.9%	20.7%
BP-26 Avg	**11.8%**	**19.4%**

- **The % Nameplate changes for Wind is minor.**
  - Still within the 11-12% average on previous rate cases
- **The % Nameplate changes for solar is big.**
  - Solar shows a substantial increase since the previous time rates were set in BP-22.

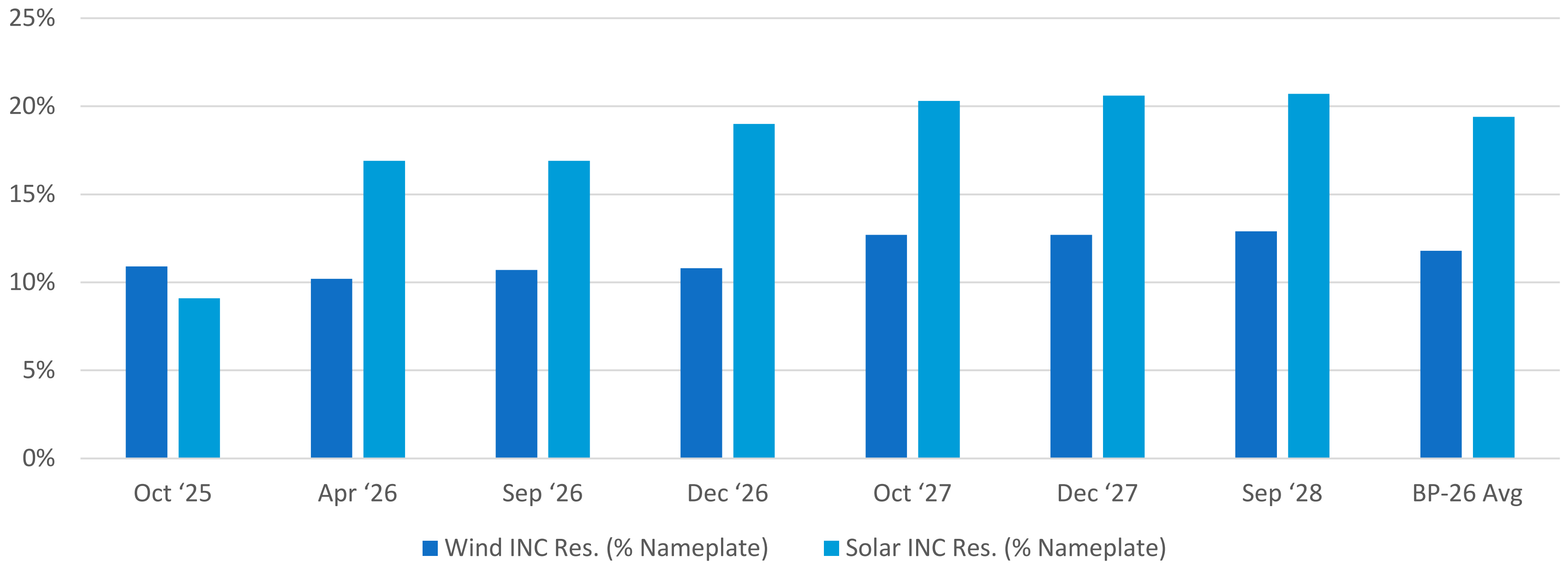
Drivers of the % Nameplate Increase

- Two main drivers for increase:
  - Contribution to total reserve profile
  - Geographic diversity

Drivers of the % Nameplate Increase

- Contribution to total reserve profile.
  - Reserves are allocated based on imbalance correlation to the total imbalance signal relative to other reserve classes.
  - When **solar penetration is low**, there is little correlation between solar imbalance and total imbalance.
  - If there is a **significant increase in solar penetration**, solar will be a much **bigger contributor** to the total imbalance signal.
  - **This outcome is expected.**
    - As part of a settlement agreement, we provided a solar study in BP-18 that showed a balancing reserve forecast assuming solar growth across the BA up to 2000 MW. We showed that the solar reserves as a percent of nameplate grows significantly as solar penetration grows, until it eventually levels off. In that study, we saw reserves as a percent of nameplate get as high as 19%.

Contribution to Total Reserve Profile



Drivers of the % Nameplate Increase

- Geographic Diversity
  - In general, a **single large VER plant has a larger imbalance contribution** than a few plants with the same aggregate nameplate spread out across a wider area (e.g. a single 600 MW plant in one location vs. three 200 MW plants spread throughout the BA).
  - This is because the spread-out plants have **geographic diversity**, meaning weather impacts leading to imbalance at one site may not be occurring at the others (e.g. intermittent clouds at one site vs. clear day at others).
  - We ran a **small study** to test this, assuming three 200 MW plants at three different locations where solar exists in the BA today as a comparison to a single 600 MW plant. This resulted in **reserves as a percent of nameplate around 13%** for the geographically diverse scenario compared with approximately 17% for the non-geographically diverse.

Capacity Costs

Preliminary BP-26 Capacity Costs

- Please refer to the Generation Inputs Capacity Costs materials presented yesterday, August 27 for detailed information.

Other Considerations

DERBS Settlements

- A portion of the DERBS rate increase is due to settlements in BP-22 and BP-24.
- BP-22
  - The DERBS rate increase was mitigated by half and the costs were spread among other rates.
  - It was anticipated that the full increase would take effect in BP-24 and all costs would be recovered through DERBS.
- BP-24
  - All rates were held flat, so the anticipated increase is now expected to take effect in BP-26.

DERBS Settlement in BP-22

- A portion of the DERBS rate increase is due to settlements in BP-22 and BP-24.

Rate	Units	BP-22 Rates*
DERBS with BP-22 mitigation		
DERBS Inc	mills/kWh	21.30
DERBS Dec	mills/kWh	1.24
DERBS without BP-22 mitigation		
DERBS Inc	mills/kWh	26.90
DERBS Dec	mills/kWh	1.57

* BP-22 Rates on this table reference values while in the EIM.

Balancing Reserves Shortfall

- The forecast need for balancing reserves in BP-26 has surpassed BPA Power's threshold to provide.
  - BPA Power has a threshold of 900MW INC capacity and 1100MW DEC capacity
  - The rate case average used to set rates is 1127MW INC and 1200MW DEC
- The method for filling the gap has yet to be identified.
- An assumption must be made for the cost of these additional reserves for cost recovery purposes.

Balancing Reserves Shortfall

- The costs are currently assumed to be the capacity costs provided by BPA Power, provided on previous slides.
- The total costs needed to be recovered through Transmission balancing rates is $175m.
  - $145m of this will be used for BPA Power's balancing capacity.
  - $30m of this will be used to recover the costs of filling the shortfall.

Next Steps

- September
  - Further discussion of the Transmission Rates impacts of the Balancing Reserves Shortfall.
  - Review any customer feedback received.

Summary

Preliminary BP-26 Rates

Rate	Units	BP-24 Rates	BP-26 Rates	Percent Change
RFR				
Regulation and Frequency Response	mills/kWh	0.44	0.45	2.3%
OR				
Operating Reserves - Spinning	mills/kWh	11.05	15.93	44.2%
OR - Spinning Default	mills/kWh	12.71	18.32	44.1%
Operating Reserves - Supplemental	mills/kWh	7.22	9.48	31.3%
OR - Supplemental Default	mills/kWh	8.30	10.90	31.3%
DERBS				
DERBS Inc	mills/kWh	21.30	74.30	248.8%
DERBS Dec	mills/kWh	1.24	0.00	-100.0%
VERBS				
VERBS Wind Regulating	mills/kW-mo	0.36	0.41	14.5%
VERBS Wind Non-Regulating	mills/kW-mo	0.40	0.36	-8.9%
VERBS Solar Regulating	mills/kW-mo	0.28	1.76	524.1%
VERBS Solar Non-Regulating	mills/kW-mo	0.17	0.99	469.0%

B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

Generation Interconnection Withdrawal Penalties

Steps 5-6

Customer Feedback

- ## NIPPC and RNW Joint Comments

  Security

  – NIPPC and RNW recommend requiring customers to post security to cover potential withdrawal penalties to ensure that customers who withdraw are able to cover the costs associated with penalties when their withdrawal does not trigger an exception. We look forward to working with BPA to address the specific mechanisms and processes for BPA to request and customers to provide security for potential withdrawal penalties.

  General

  – In summary, we encourage BPA to adhere to FERC Order 2023 and 2023-A as closely as possible, while recognizing that BPA must also implement tariff changes that are consistent with both the spirit and letter of the TC-25 Settlement Agreement. While we appreciate BPA staff's efforts in providing customers with a range of alternatives to consider, NIPPC and RNW believe that the recommendations set forth above effectively conform Order 2023 and 2023-A to the TC-25 Settlement Agreement. We look forward to reviewing a proposal from BPA and working with BPA and other customers to develop a more refined withdrawal penalty mechanism.

Customer Feedback

- Savion Comments

  Phases and Stages

  – Savion believes the splitting of the Phase 1 and Phase 2 Studies into separate Stages is unnecessary, confusing and will ultimately lead to excessive administrative efforts for both BPA and Interconnection Customers.

  Security

  – Both Study Deposits and separate Security Postings should be required for a GI request to advance through the Transitional and Durable Study processes.

  General

  – In closing, Savion prefers BPA's Alternative 2 due to its cost-causation principles found in the "% of Allocated Costs" criteria. If Alternative 2 were also paired with an up-front gating mechanism comparable to the Volumetric Price Escalator proposed in Savion's May 9th presentation, we believe BPA would have a very strong GI study framework that will thwart the vast majority of unproven GI study requests while standing up to the scrutiny of GI customers seeking just and reasonable treatment.

Customer Feedback

- Avangrid

  Timeline

  – Given the timing of a potential implementation of withdrawal penalties during the current Transition Cluster, Avangrid reiterates that a penalty-free withdrawal during the Transitional Cluster is appropriate. Assuming the withdrawal penalties will be effective October 1, 2025, however, and acknowledging that the first GI decision point after that date remains uncertain, Avangrid also believes that applying an Alternative 2 withdrawal penalty during a Phase 1 restudy (or any decision point after the TC-26 tariff effective date) in the Transitional Cluster could also be appropriate.

  General

  – Avangrid continues to believe that withdrawal penalties are a critical component of FERC's interconnection cluster study process and sees little reason to deviate from FERC rules.

Customer Feedback

- Seattle City Light

  Timeline

  – City Light suggests that any GI cluster study/restudy agreement, FAS agreement, LGIA's or study agreement extensions executed after September 30th, 2025, should be subject to GI Withdrawal Penalty provisions.

  General

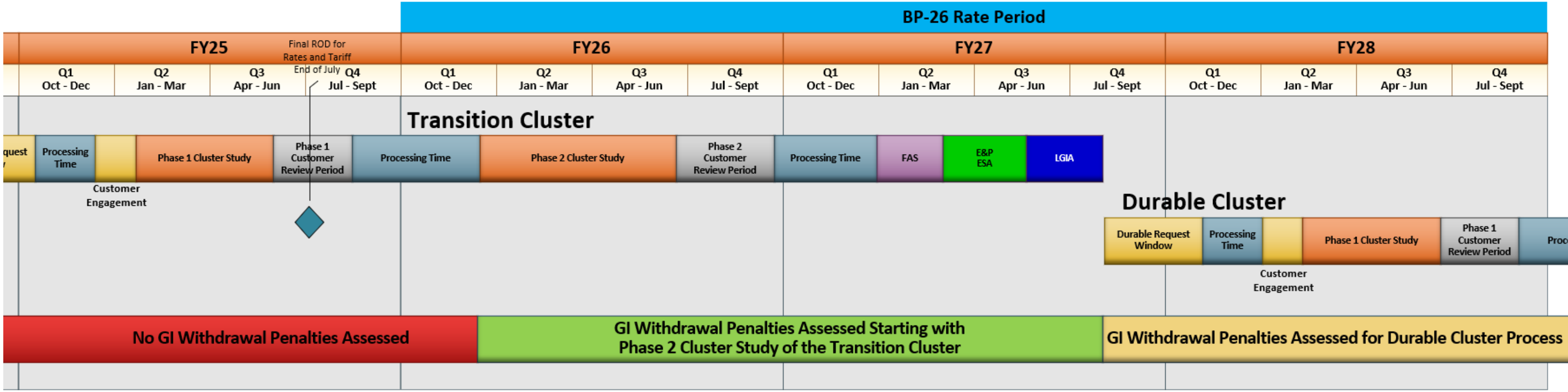
  – The Stage 2, Phase 1 Study should not have a withdrawal penalty. We suggest it is best to incentivize requestors to evaluate results and withdraw at the end of this stage.
  – Requesters should know if they move forward after Stage 2, Phase 1 Study, they will face significant escalating withdrawal penalties.
  – Requesters should believe that they will not qualify for exceptions from withdrawal penalties under most conditions

Additional Deposits or Securitization

- In the TC-25 Record of Decision, BPA adopted the TC-25 Settlement Agreement, requiring customers to demonstrate commercial readiness to advance through the Cluster Study.
- Parties to the TC-25 Settlement Agreement agreed to allow customers to provide either non-financial evidence of commercial readiness or a deposit in lieu of evidence. The settlement agreement did not include a requirement that customers provide a security deposit to execute a Large Generator Interconnection Agreement (LGIA).
- BPA will not propose a new financial requirement or to hold the study deposits or commercial readiness deposits adopted in the TC-25 Settlement to secure withdrawal penalties.
  - Adopting non-financial Commercial Readiness is incongruous with a system that uses Commercial Readiness Deposits as security for a withdrawal penalty.
  - BPA may re-consider the requirements for customers to advance their requests through the cluster study process, including a security deposit, in a future tariff proceeding.

BP-26 Cluster Study Timeline if Withdrawal Penalties are Assessed

- If Withdrawal Penalties are assessed in BP-26, they will start once a new phase is entered after Oct 1, 2025.



Alternatives

- Three alternatives have been identified
  - Alternative 1: Status Quo – No Penalties
  - Alternative 2: Penalties start Cluster Study Phase 2 (Similar to Pro Forma: Order 2023/2023A)
  - Alternative 3: Early and Increasing Penalties

Alternative 1: Status Quo – No Penalty

- A customers may withdraw an Interconnection Request during any part of the process without being subject to any Withdrawal Penalty.

Alternative 2: Penalties Assessed starting Cluster Study Phase 2 (Similar to Pro-Forma)

Calculation of the penalty amount

- Upon withdrawal, an Interconnection Customer will be subject to a penalty that is the greater of the currently applicable study deposit requirement or a penalty in accordance with the table below:

Stage of Withdrawal	Penalty Amount
After the Phase Two Study has commenced but before the Interconnection Facilities Study has commenced	5% of the Interconnection Customer's Network Upgrade costs
After the Interconnection Facilities Study has commenced but before an LGIA is signed	10% of the Interconnection Customer's Network Upgrade costs
After an LGIA is signed for the project	20% of the Interconnection Customer's Network Upgrade costs

Alternative 2: Penalties Assessed starting Cluster Study Phase 2 (Similar to Pro-Forma)

Exemptions to the Penalty

- The withdrawal does not have a material impact on the cost or timing of any Interconnection Requests in the same Cluster.
- The most recent Cluster Study or Cluster Re-Study Report identifies Network Upgrade costs assigned to the Interconnection Request that have increased by more than 25% compared to costs identified in the preceding Cluster Study Report or Cluster Re-Study Report.
- The Interconnection Facilities Study Report identifies Network Upgrade costs assigned to the Interconnection Request that have increased by more than 100% compared to costs identified in the preceding Cluster Study Report or Cluster Re-Study Report.

Alternative 2: Penalties Assessed starting Cluster Study Phase 2 (Similar to Pro-Forma)

Funds Collected Through Withdrawal Penalties

- BPA retains all funds from the penalties.
- The penalty is not something that BPA would expect happen, like other penalties charged.
- BPA prices the penalty to incent behavior that would encourage customers to enter and remain in the queue when ready to move forward.
- The penalty funds would be treated in the same manner as other penalty funds if incurred, funds would be used for operational purposes.

Alternative 3: Early and Increasing Penalties

Calculation of the penalty amount

- Upon withdrawal, an Interconnection Customer will be subject to a penalty in accordance with the table below:

Stage of Withdrawal	Penalty Amount
After the Phase One Study has commenced but before any Phase One Re-Studies have commenced	The unspent portion of the study deposit from the customer
After a Phase One Re-Study has commenced but before the Phase Two Study commences	5% of the Interconnection Customer's Network Upgrade costs
After the Phase Two Study has commenced but before the Phase Two Re-Study has commenced	7.5% of the Interconnection Customer's Network Upgrade costs
After the Phase Two Re-Study has commenced but before the Interconnection Facilities Study has commenced	10% of the Interconnection Customer's Network Upgrade costs
After the Interconnection Facilities Study has commenced but before an LGIA is signed for the project	15% of the Interconnection Customer's Network Upgrade costs
After an LGIA is signed for the project	20% of the Interconnection Customer's Network Upgrade costs

Alternative 3: Early and Increasing Penalties

Exemptions to the Penalty

- The withdrawal does not have a material impact on the cost or timing of any Interconnection Requests in the same Cluster.
- The most recent Cluster Study or Cluster Re-Study Report identifies Network Upgrade costs assigned to the Interconnection Request that have increased by more than 50% compared to costs identified in the preceding Cluster Study Report or Cluster Re-Study Report.
- The Interconnection Facilities Study Report identifies Network Upgrade costs assigned to the Interconnection Request that have increased by more than 100% compared to costs identified in the preceding Cluster Study Report or Cluster Re-Study Report.

Alternative 3: Early and Increasing Penalties

Funds Collected Through Withdrawal Penalties

- BPA retains all funds from the penalties.
- The penalty is not something that BPA would expect happen, like other penalties charged.
- BPA prices the penalty to incent behavior that would encourage customers to enter and remain in the queue when ready to move forward.
- The penalty funds would be treated in the same manner as other penalty funds if incurred, funds would be used for operational purposes.

Staff Leaning

- Staff is currently leaning towards Alternative 2: Penalties Assessed starting Cluster Study Phase 2 (Similar to Pro-Forma) for the following reasons:
  - Provides information for customers to make decision after Phase 1 without assessing a penalty as enough information to make a business decision may not be available until then
  - Incents those to withdrawal early in the process, instead of continuing to remain in the queue for the phase 2 cluster study
  - Minimize the need for a restudy in the phase 2 cluster study
  - Penalties increase after Phase 2 cluster study
    - the longer a request stays in the queue, the higher the penalty

Next Steps

- Please send any feedback, with your topic you are addressing by to BPA’s Tech Forum at techforum@bpa.gov, **by September 11**, with a cc to your Power and/or Transmission Account Executive.
- The final workshop will be on September 25, and it will be hybrid.

GI Reform

Option to Build Guidance and Update on LGIA articles “Under Review”

Objectives

- Review of the Large Generator Interconnection Agreement (LGIA) information shared in the July workshop.
- Status of Option to Build guidance.
- Update on BPA’s proposed revisions to the LGIA.
- Address July workshop customer comment.

Summary of BPA's Review of the LGIA

- For the July workshop, BPA posted a summary document and a redline of the proposed changes to the LGIA (on July 22, 2024) BPA identified:
  - Modifications to LGIA to adopt FERC's changes to the pro forma LGIA made in Order Nos. 2023/2023-A
  - Deviations from pro forma changes to LGIA adopted in Orders 2023 and 2023-A: modifications or retentions of existing language in BPA's LGIA to align with TC-25 Reforms
  - Ministerial changes due to formatting, grammar, numbering, punctuation, consistent use of defined terms, usage of acronyms, etc.
  - FERC Order 2023/2023A pro forma language changes to defer to the next tariff proceeding
  - Articles in LGIA still under review (including Article 5.1.3, Option to Build)
- BPA committed to discussing implementation of Option to Build in the August workshop
- BPA will also follow up on articles that were identified as "under review" in materials posted for the July workshop

Status of BPA Option to Build Guidance

- BPA is providing this status update in response to the following customer comment.

NIPPC and Renewable NW Joint Comment

Please provide an update on BPA's timeline to implement the reforms of FERC Order 845 allowing customers to self-build interconnection facilities. NIPPC and RNW note that BPA has already adopted the Order 845 self-build option in its tariff, but has yet to implement that functionality for transmission customers.

Status of BPA Option to Build Guidance

- BPA considers requests from Interconnection Customers to exercise the Option to Build in the LGIA on a case-by-case basis
  - Customers wish to better understand how Option to Build works.
  - BPA developing a standardized approach on Option to Build would help customers make decisions around pursuing Option to Build.
- BPA is considering how to develop guidance to help provide information for customers interested in exploring this option when they enter an LGIA.
  - BPA's implementation of the Option to Build must continue to be consistent with its statutory and legal obligations and ensure any equipment or facilities built under the option meet BPA's reliability obligations.
  - BPA is initially focusing on providing guidance on Option to Build for customers that are proceeding serially under BPA's TC-25 Tariff.

Update on Articles in LGIA “Under Review”

- Article 1, definition of “Stand Alone Network Upgrade” and Article 5.1.3, Option to Build
  - BPA proposes to defer revisions to these articles pending guidance for customers on Option to Build implementation.
  - BPA has categorized this as language changes to defer to the next tariff proceeding.
  - BPA will share its evaluation and any proposed changes to these articles in pre-proceeding workshops ahead of the next Tariff proceeding.

Update on Articles in LGIA "Under Review" (cont'd)

- Article 1, definition of "Withdrawal Penalty"
  - BPA staff will include the definition of "Withdrawal Penalty" consistent with staff leaning shared in discussion of Withdrawal Penalties and tariff language changes to Attachment L and R.
  - BPA has categorized this change as a change to align with proposals for Withdrawal Penalties for BP-26.
- These changes are reflected in the following documents posted as part of the August workshop materials:
  - Updated summary document of proposed LGIA changes.
  - Tariff redline document (includes the updated redline of the proposed LGIA changes).

NIPPC/RNW July Workshop Comment

NIPPC and RNW note that BPA proposes to retain the existing language of LGIA Section 11.5 related to Provision of Security, which applies only when construction of network upgrades is about to begin.

NIPPC and RNW also note that while BPA expressly excluded withdrawal penalties from the TC-25 process, the magnitude and other details associated with a withdrawal penalty framework are in scope for the BP/TC-26 proceeding. NIPPC and RNW are concerned that undercapitalized customers faced with withdrawal penalties may simply declare insolvency and walk away from paying withdrawal penalties that are intended to mitigate harm to BPA and its customers from the costs and delays associated with the withdrawal. NIPPC and RNW ask that BPA explain how it will recover the full amount of withdrawal penalties from insolvent customers in the absence of requiring customers to provide security for those amounts. NIPPC and RNW suggest that BPA consider including language in BPA's LGIA requiring a customer to provide security in an amount sufficient to cover the estimated withdrawal penalties that would accrue if the customer withdrew from the generator interconnection cluster study process.

NIPPC and RNW appreciate BPA's update at the July 30 workshop that it is working to implement the reforms of FERC Order 845 allowing customers to self-build interconnection facilities. As previously noted, BPA has already adopted the Order 845 self-build option in its tariff, but has yet to implement that functionality for transmission customers. NIPPC and RNW look forward to BPA's update at the August workshop with more detail and proposed LGIA redlines on this topic.

BPA Response to Comment

- During the TC-25 reforms a decision was made not to adopt a LGIA Deposit requirement in the LGIP.
- BPA is currently proposing changes to the LGIA that align with the TC-25 reforms.
- Additional changes to the LGIA outside the scope of the TC-25 reforms will be considered during the next Tariff proceeding.

Next Steps

- BPA will collect comments on this proposal
  - Please send all feedback to techforum@bpa.gov with a copy to your Account Executive.
  - Comments are due by September 11, 2024.
- You can provide feedback on the proposed LGIA changes by inserting comments in the Tariff Redline PDF document or by providing written comments.
- In written comments, please include reference to the article you are commenting on, any alternate proposed language, and the reasoning for the proposed change.
- At the September workshop, BPA will provide a final summary on this topic and address any new comments received.

TC-26 Redline Tariff Review

TC-26 Redline Tariff Review

- The draft redline tariff is posted to the Meetings and Workshops section of the BP-26 webpage with today's presentation.
  - Also posted is a list of the proposed changes discussed during the BP/TC-26 workshops; includes the proposed ministerial edits to Attachments L and R.
  - Sections still under review are marked as such.

Sections Under Review

- An updated draft redline tariff will be shared at the September 25 workshop to include the following:
  - Any proposed modifications to Schedule 9E in support of the Non-EIM Balancing proposal in the rate case.

Proposed Tariff Changes

- ROFR Queue Management
  - Section 2.2, Reservation Priority for Existing Firm Service Customers
  - Modify to allow customers to have rollover if the customer requested service for 5 years or more.
  - Issue and proposed tariff language shared at the May 22 and July 30 BP/TC-26 workshops.

Proposed Tariff Changes

- Section 4 Alignment with ATC
  - Section 4, OASIS
  - Modify to align with current Attachment C (ATC) in how ATC paths are defined.
  - Issue and proposed tariff language shared at the May 22 BP/TC-26 workshop.

Proposed Tariff Changes

- Non-EIM Balancing (BP-26 topic)
  - Schedule Schedule 9E (Generator Imbalance Service).
  - UNDER REVIEW
  - Issue shared at the June 26 BP/TC-26 workshop; proposed tariff language to be shared at the September 25 BP/TC-26 workshop.

Proposed Tariff Changes

- Network Loss Factors
  - Schedule 11, Real Power Losses Calculation
  - Modify loss factor values to reflect the two-season values calculated in the TC-26 Network Loss Factor Study.
  - Issue and proposed values shared at the July 30 BP/TC-26 workshop.

Proposed Tariff Changes

- Conditional Firm Service Exhibit
  - Attachment A, Form Of Service Agreement For Firm Point-To-Point Transmission Service
  - Minor language/description revisions for consistency within the attachment; add Exhibit F, Specifications for Conditional Firm Point-to-Point Transmission Service.
  - Issue and proposed tariff language shared at the May 22 BP/TC-26 workshop.

Proposed Tariff Changes

- GI Withdrawal Penalties
  - Attachment L, Standard Large Generator Interconnection Procedures (LGIP)
    - Definitions, Section 3.7, Section 3.7.1 (new)
    - New definition; revisions to add new penalty for GI customers that withdraw their large generator requests from the queue (set in Transmission Rate Schedules).
  - Attachment R, Large Generator Interconnection Transition Process
    - Section 1.1, Section 4.8 (new)
    - Revisions to add new penalty for GI customers that withdraw their large generator requests from the queue (set in Transmission Rate Schedules).
  - Issue shared as part of transmission rates topics at the April 24 and June 26 BP/TC-26 workshop; proposed tariff language shared at the August 27-28 BP/TC-26 workshop.

Proposed Tariff Changes

- GI Reform – LGIA
  - Attachment L (LGIP), Appendix 5
  - Add the revised Large Generator Interconnection Agreement (LGIA), which incorporates reforms adopted in TC-25.
  - Issue and draft proposed tariff language shared at the April 24 and July 30 BP/TC-26 workshop; final proposed tariff language shared at the August 27-28 BP/TC-26 workshop.

Proposed Tariff Changes

- Transmission Line Ratings
  - Attachment S (New)
  - Supports BPA's implementation of FERC Order 881
  - Issue shared at the May 22 BP/TC-26 workshop; final proposed tariff language shared at the July 30 BP/TC-26 workshop.

Proposed Tariff Changes

- Corrections and Ministerial Changes
  - Clean up of Attachments L and R adopted in TC-25
    - Grammar, capitalization, formatting.
    - See separate table posted on BP-26 webpage for complete list of affected sections.
  - Attachment R, Section 4.2
    - Revision to reflect correct cure period adopted in TC-25.

TC-26 Settlement

Proposed Initiation and Next Steps

Materials to be provided during the workshop.

Meeting Wrap Up and Next Steps

- Please send any feedback, with your topic you are addressing by to BPA's Tech Forum at techforum@bpa.gov, **by September 11**, with a cc to your Power and/or Transmission Account Executive.
- The final workshop will be on September 25, and it will be hybrid.

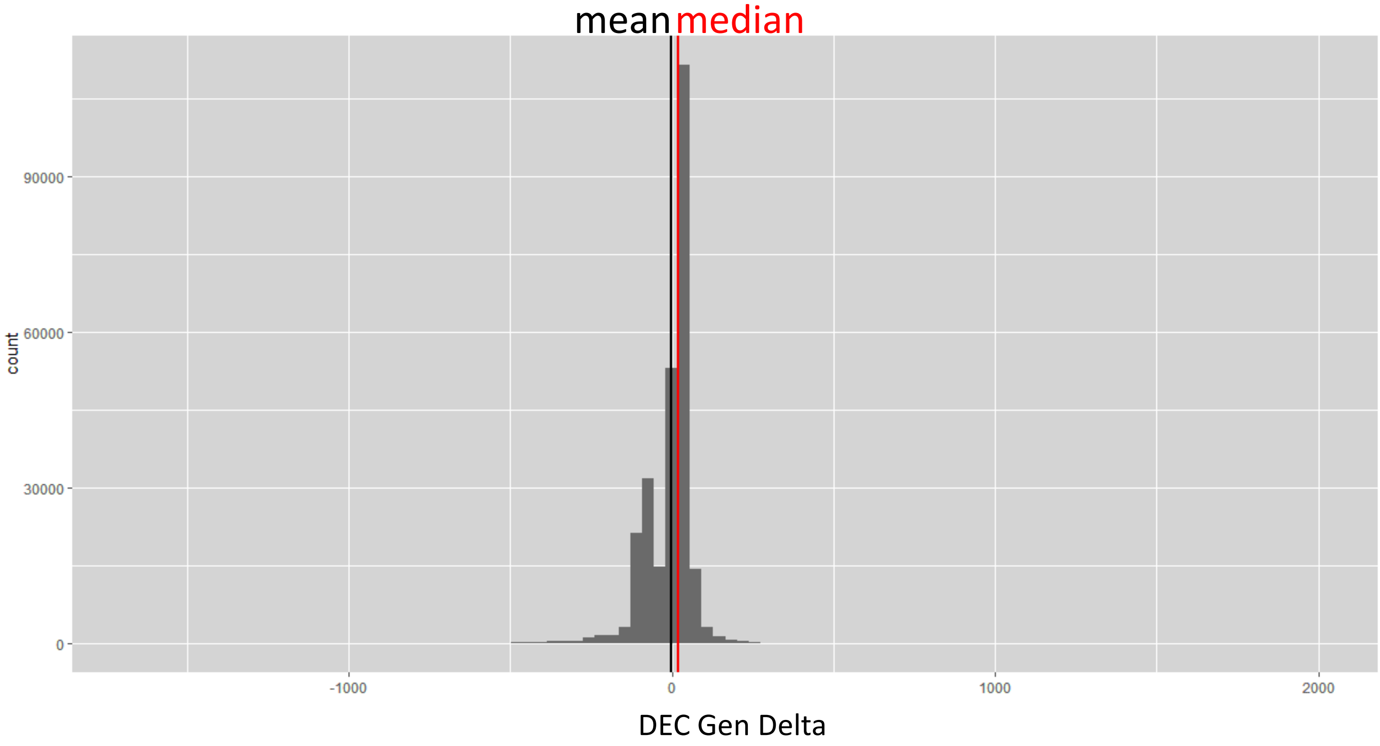
Appendix:
Generation Inputs Capacity Costs

Proposed Method in Plain Language

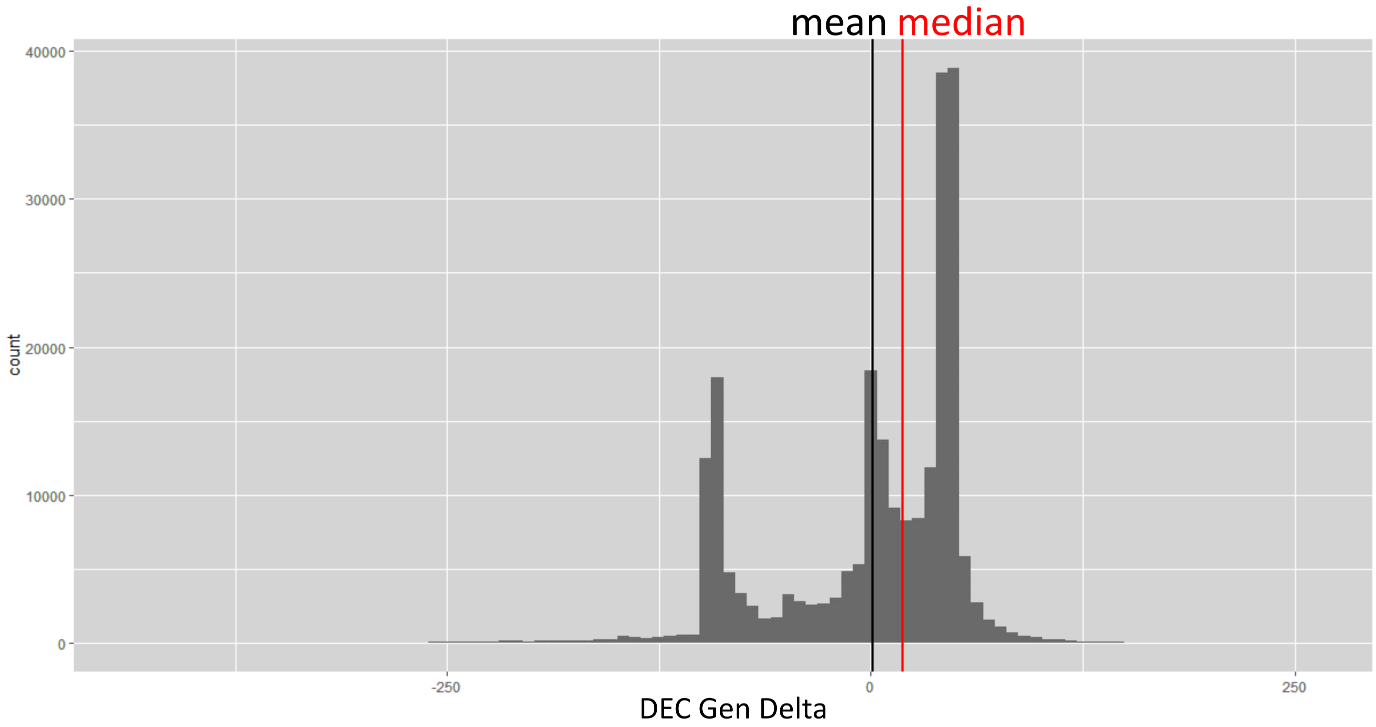
Updated methodology in plain language:

- *Step 1:* Find the generation delta between the base case (assume all reserves constraints are held) and a test case (assume a reserve constraint is removed). After the full set of deltas have been found, we remove the hourly observations that are below the 5th percentile or above the 95th percentile to remove outliers that would distort the results.
- *Step 2:* Determine the energy shift MWs of that delta by finding the daily positive gen deltas and negative gen deltas. The absolute value of the smaller of those daily total, represents the daily energy shift (MWs).
- *Step 3:* The sum of daily hourly gen deltas is the net generation delta (MWs). This net generation delta represents other impacts to the federal system beyond impact to load factoring (energy shift). These include, but are not limited to, spill and efficiency impacts.
- *Step 4:* Price the energy shift MWs for each day at the daily spread between high and low monthly prices. High and low prices are the max and min value from the monthly HLH and LLH Mid-C price sets from the Aurora forecast.
- *Step 5:* Price the net generation delta at the weighted average monthly Mid-C price from the Aurora forecast.
- *Step 6:* Sum the daily costs for each month and year to arrive at a total monthly and annual variable cost of reserves.

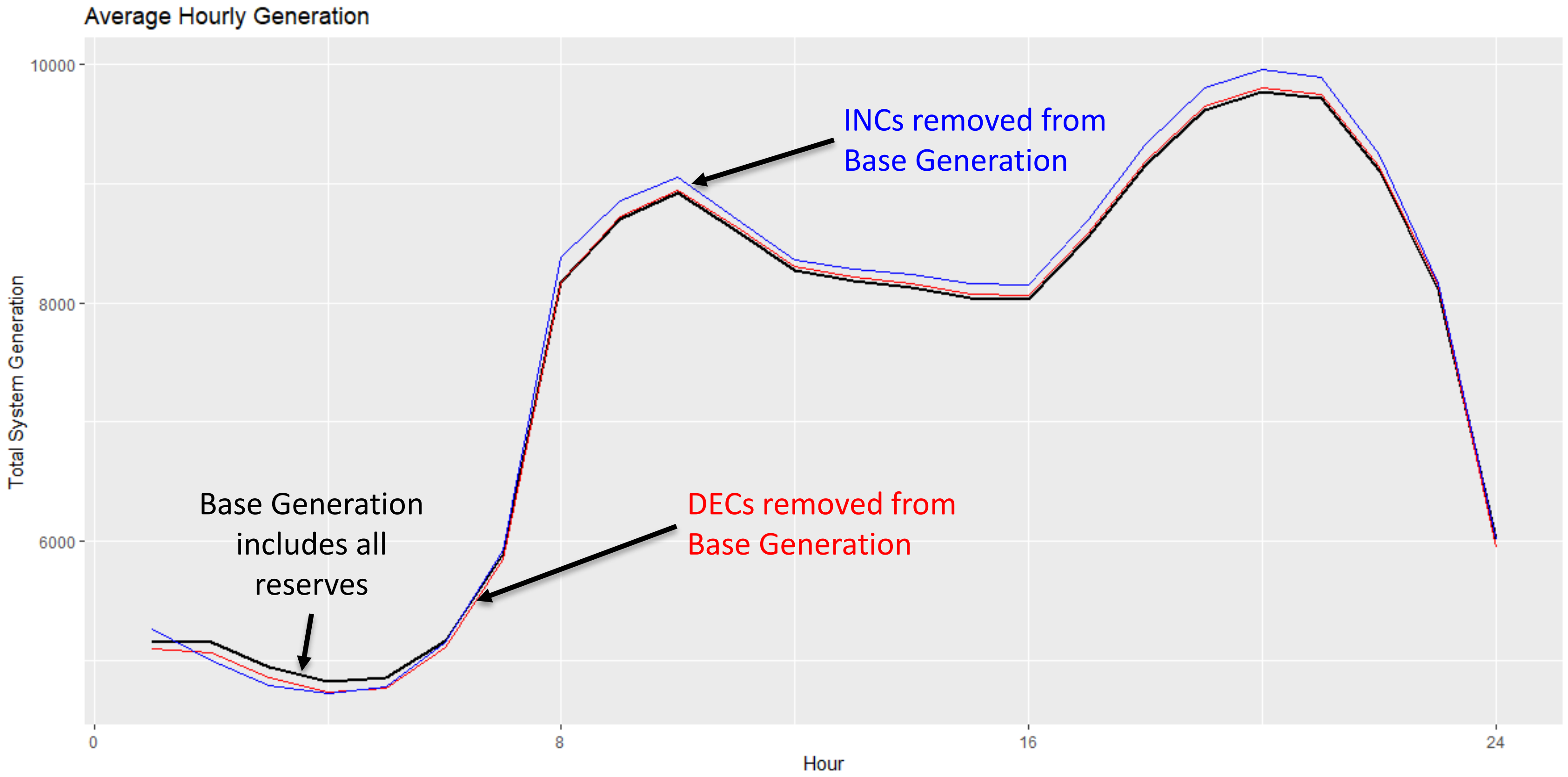
Generation Delta Distribution *Without* Adjustment



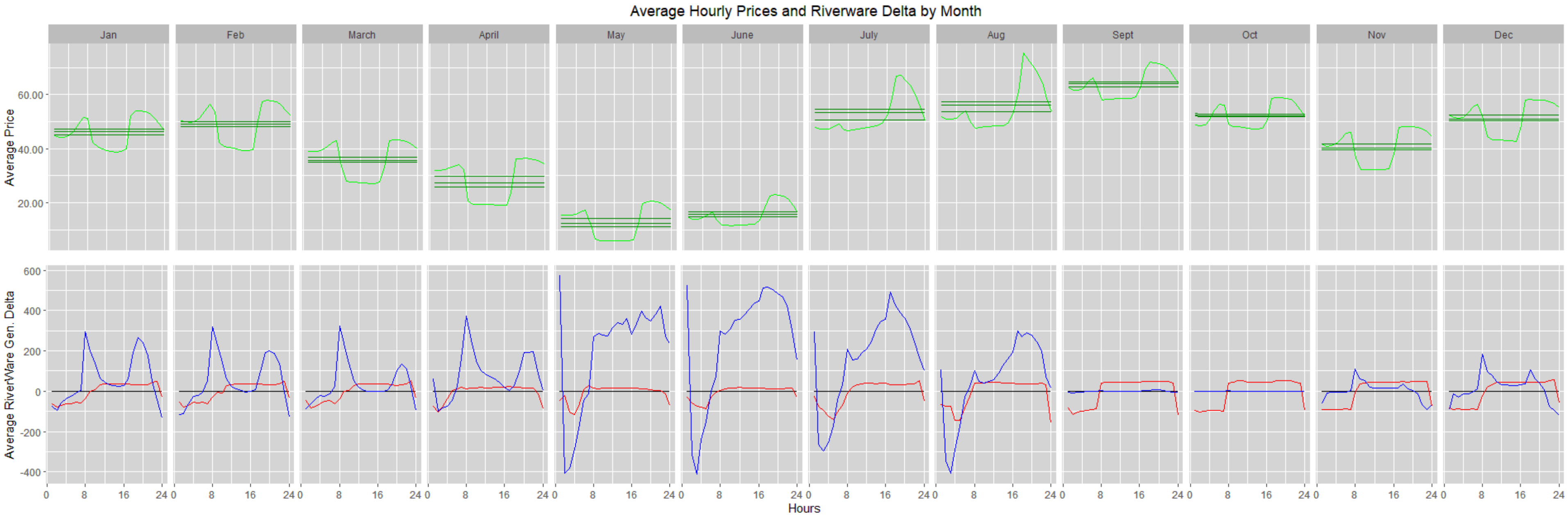
Generation Delta Distribution *With* Adjustment



Total Generation Under Each Scenario



Generation Delta and Price Data for FY26



Light Green: hourly MidC Aurora prices

Dark Green: monthly High, Avg, Low MidC Aurora prices

Red: Removed DECs from base case

Blue: Removed INCs from base case

BP-26 Test Results

Total Variable Reserve Costs :

*Generation deltas are adjusted by removing the extreme tails of the hourly distribution for each WY and Month using the 5th and 95th percentiles. High prices are taken by finding the maximum value between HLH and LLH values; Low prices are the min. Mean is the weighted average between HLH and LLH values.										DEC Costs			INC Costs		
Month	Year	ShiftMWs DEC	NetMWs DEC	ShiftMWs INC	NetMWs INC	High Price	Low Price	Mean Price	High-low Spread	DEC Shift Cost	DEC Net Cost	DEC Total Cost	INC Shift Cost	INC Net Cost	INC Total Cost
10	2025	17,903	1,421	216	(101)	$52.63	$51.87	$52.30	$0.75	$ 13,602	$ 73,867	$ 87,469	$ 148	$ (5,212)	$ (5,063)
11	2025	16,276	719	5,634	2,177	$41.70	$39.65	$40.34	$2.05	$ 33,248	$ 27,628	$ 60,876	$ 12,195	$ 91,561	$ 103,757
12	2025	16,325	(60)	8,311	12,234	$52.33	$50.19	$50.98	$2.14	$ 35,126	$ (5,624)	$ 29,502	$ 16,990	$ 547,591	$ 564,580
1	2026	12,457	23	14,689	37,358	$47.30	$45.24	$46.39	$2.06	$ 17,165	$ (3,514)	$ 13,651	$ 37,784	$ 634,018	$ 671,802
2	2026	10,856	408	10,961	30,874	$50.14	$48.22	$49.11	$1.93	$ 18,686	$ (581)	$ 18,105	$ 22,761	$ 518,444	$ 541,205
3	2026	12,028	855	10,633	21,806	$36.82	$34.92	$35.61	$1.90	$ 23,090	$ 20,499	$ 43,589	$ 20,840	$ (169,355)	$ (148,514)
4	2026	5,926	1,087	13,898	50,506	$29.85	$25.90	$27.22	$3.94	$ 20,746	$ 66,164	$ 86,909	$ 62,401	$ 264,125	$ 326,526
5	2026	5,363	(1,497)	29,752	144,193	$14.07	$11.26	$12.21	$2.80	$ 14,591	$ (1,446)	$ 13,146	$ 76,616	$ 408,113	$ 484,728
6	2026	6,777	(1,415)	27,688	184,174	$16.63	$14.76	$15.75	$1.87	$ 11,587	$ (6,301)	$ 5,286	$ 50,534	$ 752,820	$ 803,354
7	2026	13,086	453	25,067	126,746	$54.50	$50.74	$53.24	$3.75	$ 44,608	$ 60,118	$ 104,725	$ 80,221	$ 4,093,387	$ 4,173,608
8	2026	13,913	2,300	23,308	52,731	$57.49	$53.83	$56.27	$3.66	$ 50,027	$ 150,619	$ 200,647	$ 63,179	$ 2,278,311	$ 2,341,490
9	2026	16,655	1,576	132	(85)	$64.76	$62.91	$64.13	$1.85	$ 30,873	$ 101,656	$ 132,529	$ 119	$ (5,166)	$ (5,047)
	Total:	147,565	5,870	170,289	662,612	$43.18	$40.79	$41.96	$2.39	$ 313,348	$ 483,084	**$ 796,433**	$ 443,789	$ 9,408,637	**$ 9,852,426**

Appendix: Interconnection Credits

Non-Cash Revenues: Effect on Revenue Requirements

- A basic premise for setting rates is that Revenues from Proposed Rates must be greater than or equal to the Revenue Requirement, as measured on both an accrual and cash perspective.
- If there will be non-cash revenues in the revenue forecast, then the Revenues from Proposed Rates must be greater than the Cash Requirements to demonstrate cost recovery.
- To capture this in determining the Revenue Requirement, the Revenue Requirement is the sum of all Cash Requirements and Non-Cash Revenues.
- In the context of rate setting, LGIA credits function more like a cost than a revenue:
  - LGIA credits are based on rates that must recover in full the projected rate period costs.
  - Until the LGIA credits are exhausted, interconnection customers do not contribute cash revenues and therefore do not contribute to the recovery of rate period costs.
  - Consequentially, the remaining customers have to make up the difference.

BP-26 GI & LLI Credit and Interest Forecast

BP-26 GI & LLI Credit and Interest Forecast ($000)

Request #	Credit Method	Current Balance as of 8/1/24	Upgrade Deposits FY26-28	FY 25 Credits Forecast	FY 26 Credits Forecast	FY 27 Credits Forecast	FY 28 Credits Forecast	FY 25 Interest Forecast	FY 26 Interest Forecast	FY 27 Interest Forecast	FY 28 Interest Forecast
1	GI-2	$ 1,454	$ -	$ 138	$ 138	$ 138	$ 138	$ 45	$ 42	$ 38	$ 35
2	GI-2	$ 775	$ -	$ 138	$ 138	$ 138	$ 138	$ 22	$ 18	$ 14	$ 10
3	GI-1	$ 36,453	$ -	$ 7,416	$ 7,416	$ 7,416	$ 7,416	$ 1,140	$ 913	$ 678	$ 435
4	GI-1	$ 8,277	$ -	$ 791	$ 791	$ 791	$ 791	$ 295	$ 276	$ 257	$ 237
5	GI-1	$ 1,973	$ -	$ 672	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	GI-1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	GI-1	$ 1,024	$ -	$ 109	$ 300	$ 570	$ 124	$ 32	$ 26	$ 13	$ 0
8	GI-1	$ 181	$ -	$ 150	$ -	$ -	$ -	$ 2	$ -	$ -	$ -
9	GI-1	$ 8,567	$ 35,789	$ -	$ 742	$ 2,719	$ 5,686	$ 475	$ 842	$ 884	$ 817
10	GI-1	$ 22,551	$ -	$ 772	$ 2,130	$ 4,048	$ 4,212	$ 390	$ 371	$ 322	$ 254
11	GI-1	$ 196	$ -	$ 167	$ -	$ -	$ -	$ 2	$ -	$ -	$ -
12	GI-1	$ 1,505	$ -	$ 198	$ 198	$ 198	$ 198	$ 45	$ 40	$ 35	$ 30
13	GI-1	$ 579	$ -	$ 198	$ 198	$ 180	$ -	$ 14	$ 8	$ 2	$ -
14	GI-1	$ 3,348	$ -	$ 2,790	$ -	$ -	$ -	$ 10	$ -	$ -	$ -
15	GI-1	$ 5,938	$ -	$ 435	$ 1,200	$ 2,281	$ 2,373	$ 190	$ 169	$ 116	$ 42
16	GI-1	$ 10,201	$ 5,777	$ -	$ 435	$ 1,200	$ 2,281	$ 277	$ 278	$ 269	$ 243
17	GI-1	$ 7,277	$ 112,000	$ -	$ -	$ -	$ 2,193	$ 121	$ 371	$ 1,699	$ 1,992
18	GI-1	$ 1,503	$ -	$ -	$ -	$ -	$ -	$ 24	$ 25	$ 25	$ 26
19	GI-1	$ 2,225	$ 5,315	$ -	$ 1,735	$ 5,206	$ 1,059	$ 164	$ 184	$ 98	$ 0
20	GI-1	$ 77	$ -	$ 24	$ 24	$ 24	$ 5	$ 1	$ 1	$ 0	$ 0
21	GI-1	$ 234	$ -	$ -	$ 238	$ -	$ -	$ 3	$ 0	$ -	$ -
22	GI-1	$ 2,769	$ 4,947	$ -	$ 415	$ 989	$ 1,463	$ 217	$ 262	$ 245	$ 212
23	GI-1	$ 2,995	$ 22,522	$ -	$ -	$ 1,648	$ 2,637	$ 448	$ 894	$ 899	$ 852
24	GI-1	$ 2,700	$ -	$ -	$ -	$ -	$ -	$ 116	$ 121	$ 126	$ 132
25	GI-1	$ 751	$ 3,150	$ -	$ 593	$ 2,900	$ 780	$ 98	$ 165	$ 93	$ 1
26	GI-1	$ 1,719	$ 4,445	$ -	$ -	$ 554	$ 1,034	$ 72	$ 259	$ 259	$ 236
27	GI-1	$ 1,556	$ 3,369	$ -	$ -	$ 3,955	$ 1,407	$ 65	$ 207	$ 143	$ 6
28	GI-1	$ 2,793	$ 13,094	$ -	$ 79	$ 1,002	$ 1,635	$ 273	$ 731	$ 737	$ 710
29	Non-GI (NT)	$ 1,545	$ -	$ 85	$ 139	$ 139	$ 139	$ 46	$ 43	$ 41	$ 38
30	Non-GI (NT)	$ 275	$ -	$ 252	$ -	$ -	$ -	$ 2	$ -	$ -	$ -
31	Non-GI (NT)	$ 724	$ -	$ 163	$ 418	$ 150	$ -	$ 11	$ 6	$ 0	$ -
32	Non-GI (NT)	$ 7,266	$ -	$ 632	$ 1,663	$ 3,162	$ 2,440	$ 228	$ 197	$ 123	$ 24
33	Non-GI (NT)	$ 517	$ -	$ 167	$ 171	$ 170	$ -	$ 8	$ 5	$ 2	$ -
34	Non-GI (NT)	$ 60,603	$ -	$ 1,542	$ 6,197	$ 10,764	$ 12,186	$ 706	$ 670	$ 572	$ 440
35	Non-GI (NT)	$ 1,260	$ -	$ 533	$ 694	$ -	$ -	$ 15	$ 5	$ -	$ -
36	Non-GI (NT)	$ 52	$ -	$ 52	$ -	$ -	$ -	$ 0	$ -	$ -	$ -
37	Non-GI (NT)	$ 13,138	$ -	$ 3,292	$ 9,432	$ 1,130	$ -	$ 405	$ 199	$ -	$ -
38	Non-GI (NT)	$ 6,365	$ -	$ -	$ -	$ 605	$ 6,879	$ 277	$ 288	$ 301	$ 120
39	Non-GI (NT)	$ 3,104	$ -	$ 84	$ 409	$ 760	$ 877	$ 122	$ 118	$ 98	$ 68
40	Non-GI (NT)	$ 3,037	$ -	$ 84	$ 409	$ 137	$ -	$ 129	$ 68	$ -	$ -
41	Non-GI (NT)	$ 96	$ -	$ -	$ -	$ 105	$ -	$ 3	$ 3	$ 2	$ -
42	Non-GI (NT)	$ 857	$ -	$ 758	$ 117	$ -	$ -	$ 13	$ -	$ -	$ -
43	Non-GI (NT)	$ 35,430	$ -	$ 1,706	$ 1,706	$ 1,706	$ 1,706	$ 631	$ 611	$ 591	$ 570
44	Non-GI (NT)	$ 519	$ -	$ 171	$ 171	$ 171	$ 1	$ 11	$ 7	$ 2	$ -
45	Non-GI (NT)	$ 299	$ -	$ 171	$ 122	$ -	$ -	$ 5	$ 1	$ -	$ -
46	Non-GI (NT)	$ 7,999	$ -	$ 439	$ 1,170	$ 2,193	$ 2,193	$ 235	$ 217	$ 172	$ 111
47	Non-GI (NT)	$ 3,101	$ -	$ 274	$ 366	$ 975	$ 1,709	$ 72	$ 65	$ 50	$ 17
Total Forecast		***$ 275,806***	***$ 210,408***	***$ 24,402***	***$ 39,954***	***$ 58,125***	***$ 63,702***	***$ 7,458***	***$ 8,705***	***$ 8,905***	***$ 7,656***

Appendix: BP/TC-26 Logistics

BP-26 and TC-26 Workshops: Proposed Dates for Topics

Date	Rate/Tariff Topics
September 25 (Wed)	**Transmission Rates** • Utility Delivery Segment • Non-EIM Balancing • GI Withdrawal Penalties **Power Rates** • WRAP • ESS • Tier 2 Rates • UAI • Demand Rate • Gen Inputs Capacity Cost • Transfer Service Delivery • Risk (Power and Transmission)